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The Role of Methane in Limiting CO_2 EOR: Case Study of Offshore Gulf of Mexico Oil Reservoirs

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The Role of Methane in Limiting CO_2 EOR:

Case Study of Offshore Gulf of Mexico Oil Reservoirs

by

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Dedication

To my parents,

Emmanuel and Caroline, Amaranjeme

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Abstract

The Role of Methane in Limiting CO_2 EOR:

Case Study of Offshore Gulf of Mexico Oil Reservoirs

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The University of Texas at Austin, 2015

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Data from the US Department of Interior - Bureau of Ocean and Energy Management - 2012 Offshore Gulf of Mexico Atlas were analyzed to: (i) compute reconnaissance-level estimates of CO_2 volume for storage in sub-seabed offshore Gulf of Mexico (GoM) oil sands before and after carbon dioxide (CO_2) enhanced oil recovery (EOR), (ii) investigate technical and economic impacts of CO_2 injection in gas-rich offshore GoM hydrocarbon fields, and (iii) analyze legal issues and framework associated with offshore geologic sequestration or storage (GS).

Part (i) of this study, Reconnaissance-level estimation of CO_2 sub-seabed GS potential in offshore GoM, builds on a similar study conducted by The University of Texas At Austin, Bureau of Economic Geology on potential onshore CO_2 GS in the GoM region, published in Nunez-Lopez et al. (2008). Part (ii) focuses on the use of two screening methodologies to investigate the impact of native methane (CH_4) in recycled CO_2. The impact of CH_4 on the effectiveness of CO_2 as a solvent for EOR is defined by:

- Calculating minimum miscibility pressure (MMP) of pure CO_2 for each oil sand (conventional oil reservoirs)
- Computing impure CO_2 MMP for each oil sand considering only native CH_4 as an impurity and neglecting other trace gas components in the oil reservoir. Five to 50 mole percent CH_4 impurity factor was computed as a function of the pseudocritical temperature (T_{pc}) of the CH_4-CO_2 mixture.
- Plotting miscibility against sub-seabed depth, total depth, play type, and API gravity.

Part (iii) analyzes existing US outer continental shelf (OCS) regulations under the authority of the US Department of the Interior stated in Title 30 CFR Part 250 and Part 550 to determine their applicability to carbon capture, offshore GS, and CO_2 EOR.

The study results show a potential storage capacity of approximately 3.5 billion metric tons of CO_2 after CO_2 EOR for the 3,598 offshore GoM individual oil sands assessed in Part (i). For Part (ii), results indicate that deeper reservoirs are most tolerant to miscible impure CO_2 EOR. Of the play types defined by the BOEM, fan and fold belt plays are most tolerant to impure CO_2 flooding. Further study on the impact of impure CO_2 on MMP resulted in a definition of 18 mole percent as the cutoff for economic and technically viable CO_2 flooding in offshore GoM oil fields. When a hypothetical CO_2 injection stream exceeded 18 mole percent CH_4 contamination, 72% of the case study oil reservoirs became immiscible. In Part (iii), policies that address offshore CO_2 GS, CO_2 EOR, and both price based and non-price based mechanisms in the OCS would accelerate a shift towards implementing GS and CO_2 EOR in offshore GoM.

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INTRODUCTION

From 347 CE when the earliest oil wells were drilled in China, to recent deep and ultra-deep discoveries, global demand for oil has increased enormously. To meet this growing energy demand, petroleum companies explore new oil fields as well as apply enhanced oil recovery (EOR) technology in existing oil fields after exhausting oil recovery potential through primary and secondary recovery. On average, primary and secondary oil recovery extracts less than 50 percent of the original oil in the reservoir, creating the need to extract residual oil through EOR methods. The Barufet (2001) flow chart describes oil recovery beginning from discovery phase through all oil recovery phases in figure 1.

EOR methods improve production in hydrocarbon reservoirs in four ways by impacting (i) sweep efficiency, (ii) displacement efficiency, (iii) mobility ratio, and (iv) capillary forces. The EOR techniques practiced today are: gas floods, polymer floods, thermal methods, chemical floods and microbial processes. Polymer flooding and thermal methods improve mobility ratio by decreasing the mobility of the injected fluid, and by increasing the mobility of hydrocarbons, respectively (Bondor et al., 2005). Other EOR methods such as chemical flooding, microbial processes, and miscible gas flooding impact capillary forces and improve displacement efficiency. Approximately 400 billion barrels of oil can be potentially recovered from the US oil reserves by applying all enhanced oil recovery techniques (Kusskraa et al. 2013). The Energy Institute Administration (EIA) estimated up to 240 billion barrels of additional oil could be recovered through CO_2 EOR alone in the US oil fields (EIA 2011).

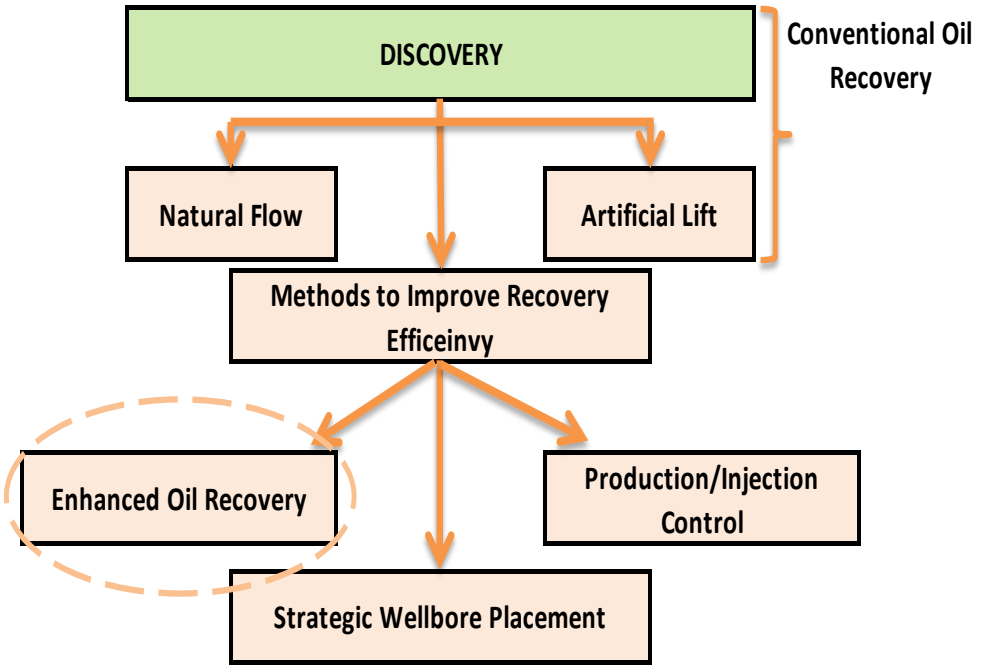

Figure 1: Methods to improve recovery efficiency (from Barufet, 2001)

For over 30 years, oil operators have successfully injected pure CO_2 into US onshore oil reservoirs to improve recovery efficiency. This study however focused on offshore EOR operations based on locally sourced impure or anthropogenic CO_2. Nearly pure CO_2 reservoirs occur naturally in certain geologic formations. The impurities in anthropogenic CO_2 vary according to the source or feedstock. Anthropogenic CO_2 is captured from large volume emitters such as coal or gas fired power plants, oil refineries, natural gas processing plants, and other major industrial emitters, as shown in figure 4. The capture process is just one step in the carbon capture and storage (CCS) or carbon sequestration process cycle. CCS involves capture of CO_2 from an emitting facility, its processing and separation, transportation via ships, tankers and/or pipelines, and injection into a geologic formation for long term storage. Figure 2 depicts CO_2 injection for GS and EOR.

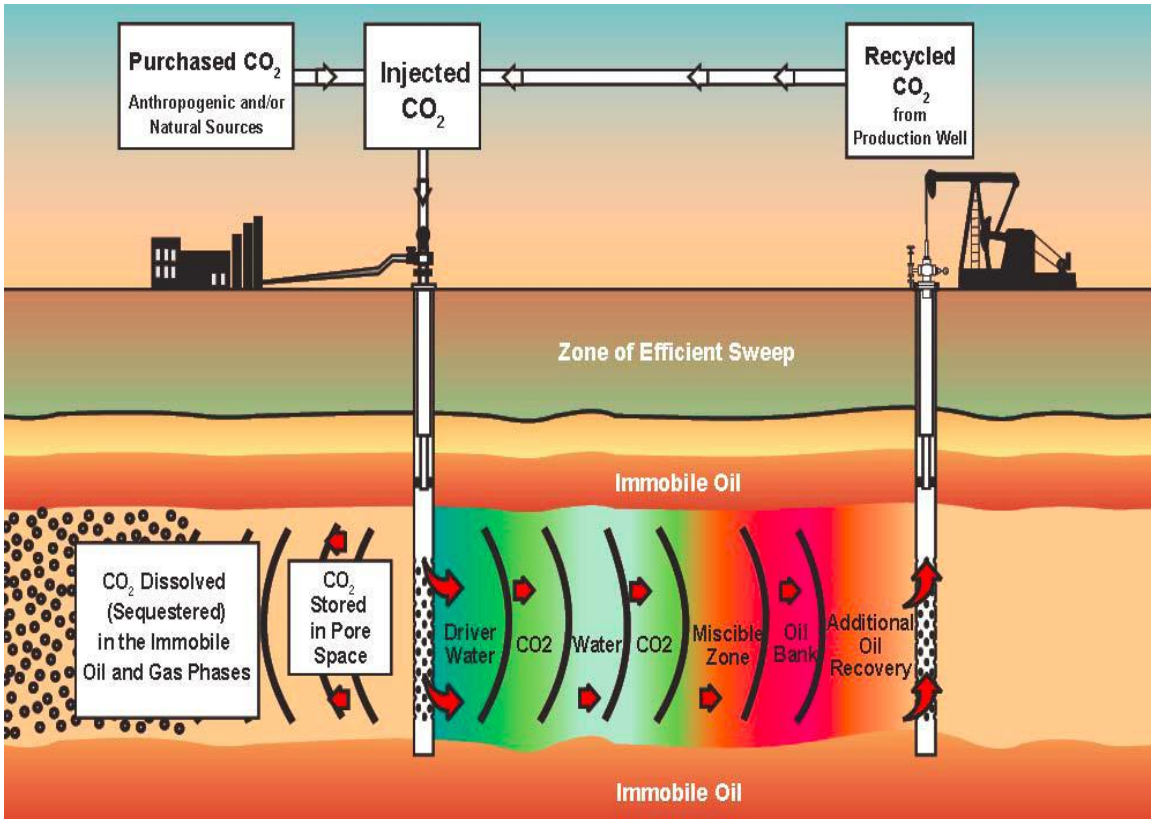

Figure 2: CO_2 injection cycle (adapted from Kuustraa et al. 2014)

Over the years, greenhouse gas (GHG) emission has become a global climate concern for the public, environmental regulatory organizations, and national governments. One solution is to reduce emission from large volume anthropogenic (LVA) CO_2 facilities to as low as reasonably practical by retrofitting carbon capture systems into an existing LVA-CO_2 facility, or incorporating CCS in the design of future LVA- CO_2 facilities. According to the International Energy Agency (IEA), CCS technology could reduce global CO_2 emissions by 19 percent (IEA, 2009). Presently, there are four prominent CCS facilities in the world which are: Sleipner and Snovhit in Norway, Weyburn in Canada, and In-Salah in Algeria. Hitherto, the 1980s US offshore CO_2 EOR pilot projects and other recent similar experimental projects are yet to be implemented on a commercial scale.

HISTORY AND OVERVIEW

In 1972, Chevron carried out the first experimental model of CO_2 miscible EOR injection at SACROC oil field in the onshore Permian Basin of West Texas (Meyer, 2007). Although the first US offshore wells were drilled in the late 1800s, the first five US offshore CO_2 EOR experiments were not performed until the early 1980s (Malone et al. 2014). These pioneering offshore CO_2 EOR pilot projects described in Malone et al. (2014) are situated in GoM coastal waters and Louisiana bay. Over two decades later, the US Department of Energy (DOE) initiated its carbon sequestration program (Pollak et al., 2011). Other countries are in process or have implemented climate change reforms to mitigate the impact of greenhouse gases to the environment. Figure 3 shows year 2014 ranking of CO_2 emitters worldwide based on global CO_2 emissions. China holds top rank and is followed by the US, with both countries together emitting about 39%.

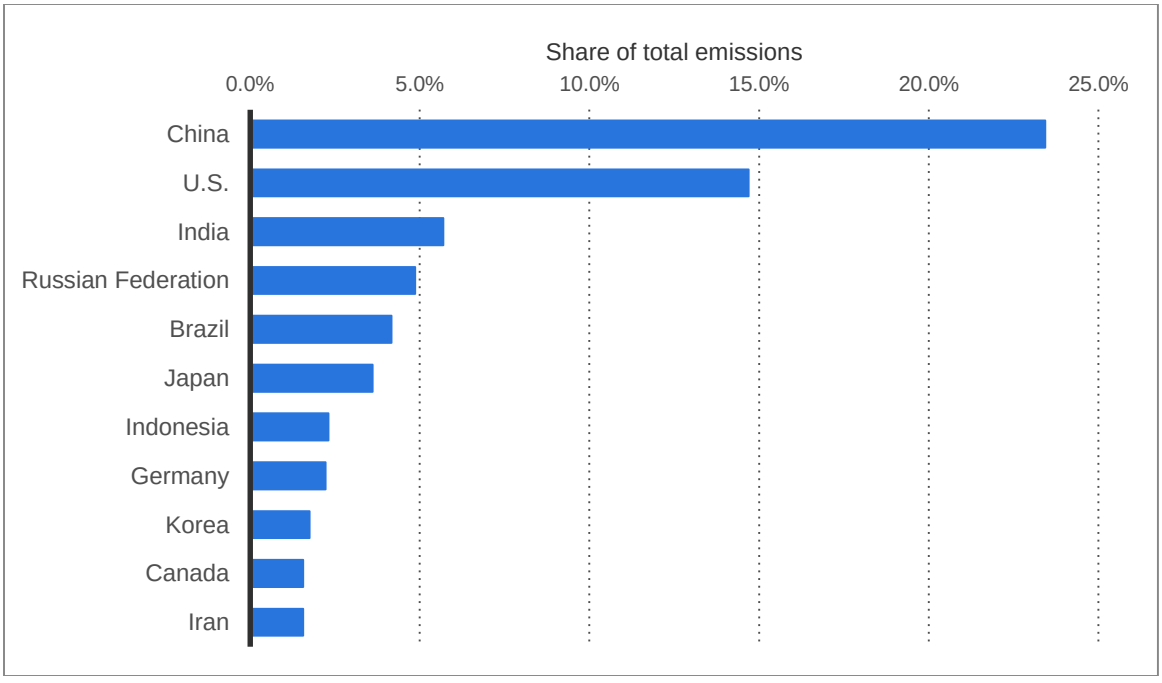

Figure 3: The largest emitters of carbon dioxide worldwide by country 2014 (retrieved from Germanwatch © Statista 2015)

Norway is currently among the low CO_2 emitters because of its carbon tax regulation. According to IEA (2012) statistics, Norway ranks 65th in global carbon emission with its contribution rated at 0.15%.

In 2013, the U.S. Environmental Protection Agency (EPA), under President Obama's Climate Action Plan, initiated plans to develop carbon pollution standards for power plants. In line with this initiative, CCS was considered a top priority technology to mitigate carbon emissions. Accordingly, carbon capture systems could be retrofitted into existing facilities of major emitters such as coal and gas fired power plants and other industrial sources. The CCS process in figure 4 is summarized in four steps below:

- Pre-combustion or post-combustion capture of CO_2 from coal-gas power plants and large industrial emitters
- Gas processing to remove impurities
- Transport of the compressed CO_2 as a supercritical fluid (usually in pipelines)
- Underground injection for long term storage of CO_2 into deep underground formations, or injection for EOR

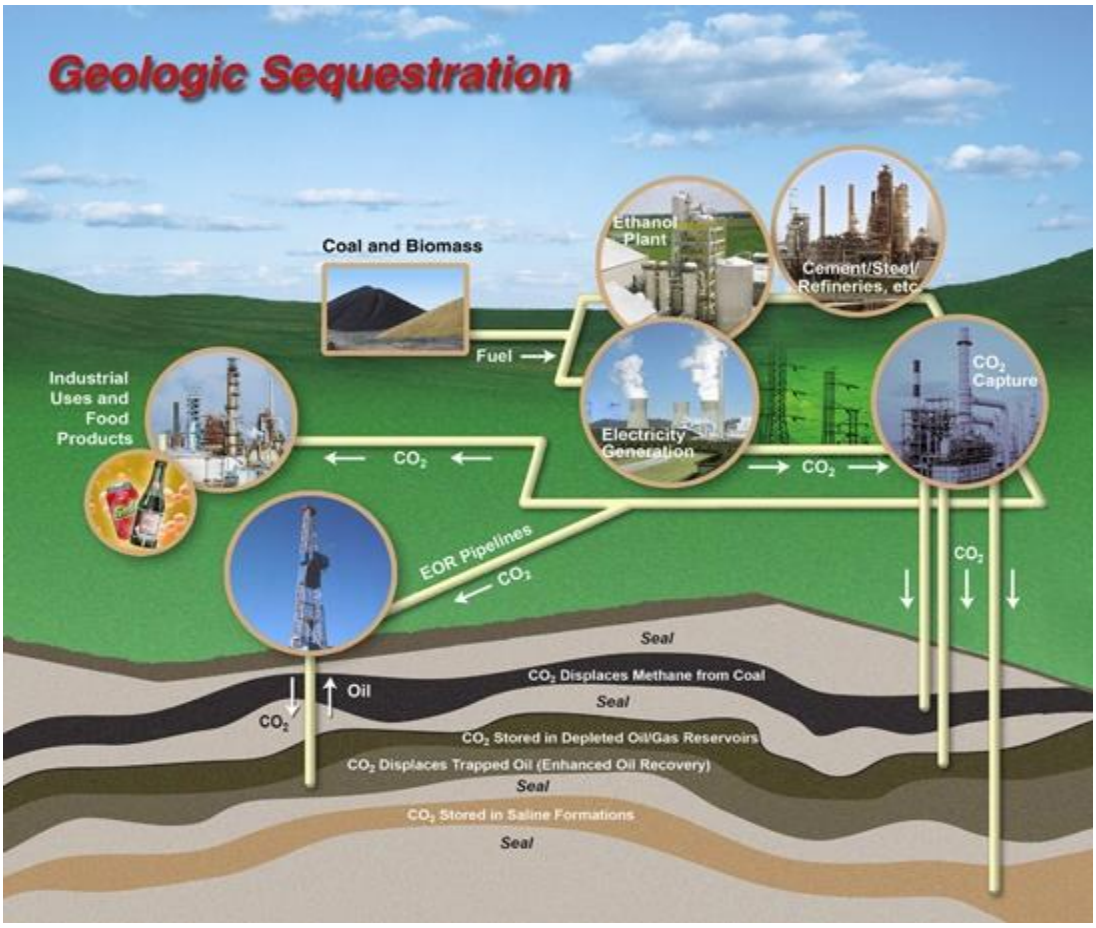

Figure 4: Carbon capture sequestration process (from the DOE/NETL, 2007)

OFFSHORE CARBON SEQUESTRATION AND EOR

Geologic sequestration (GS) stores large volumes of CO_2 in underground geological formations that would otherwise be emitted into the atmosphere. Implementing EOR with incidental GS offers additional benefits of incremental oil production, and mitigating greenhouse gas emission effect on climate respectively. The value of CO_2 as well as oil price significantly impacts CO_2 EOR economics. An economic analysis conducted for North Sea estimated the relationship between oil price per barrel and value of CO_2 for EOR that would achieve at least 10% return on investment is illustrated in figure 5 (Hustad and Austell, 2004).

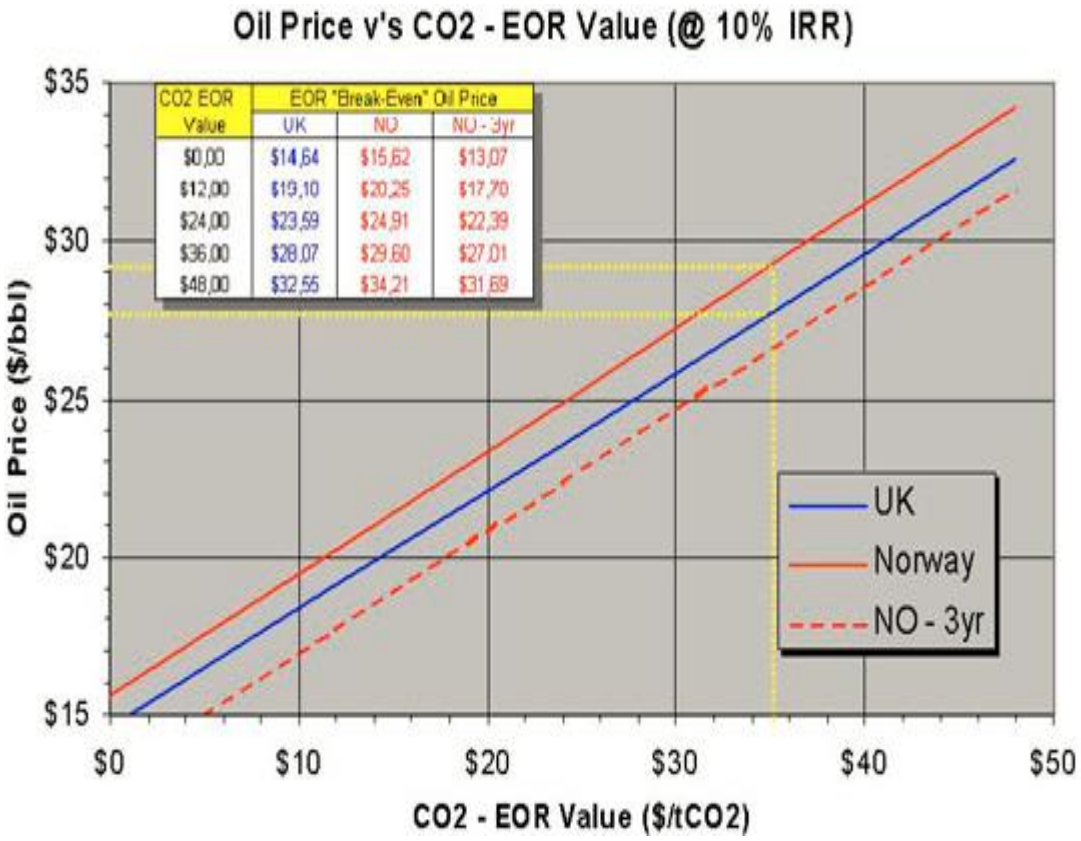

Figure 5: The relationship between oil price and value of CO_2 for EOR (from Hustad & Austell, 2004)

"*The relationship between price of oil and value of CO_2 for EOR is revealed by the three straight lines that differentiate between projects in the Norwegian sector (red), UK sector (blue), and (dashed red line) in Norway with a modified depreciation of 3 instead of 6 years. The main observation is that with oil valued below $18 /bbl then the CO_2-EOR project can only afford to pay $10 - $12 /t CO_2 (given the current economic framework). If the price for delivered CO_2 is at $35 /t CO_2, then the EOR project requires averaged oil price in range $27.80 - $29.20 /bbl to achieve 10% IRR "After-Tax" within the present taxation systems in UK / NO sectors. However this excludes an estimated $2.4 billion that would accrue to each of the respective governments as tax income generated by the project."*

The Department of Energy, National Energy Technology Laboratory report from Malone et al. (2014) estimated $50/metric ton (mt) CO_2 as the combined cost of CO_2

purchase and transport to offshore GoM. According to their CO_2 price assessment, decreasing this price by at least $10/mt is achievable if existing gas pipelines are used for CO_2 transportation, as well as initiating carbon emission regulations to propel competitive anthropogenic CO_2 markets that would increase availability of CO_2 to offshore regions.

The first commercial offshore CCS commenced in 1996 in the Norwegian North Sea Sleipner field, where CO_2 comingled in produced gas was separated and injected into the sub-seabed to prevent venting the gas into the atmosphere. These North Sea CCS projects were motivated by the Norwegian government's carbon regulations and carbon incentives programs. On the other hand, offshore CO_2 EOR operations are not yet underway. In the US, none of the five 1980s offshore CO_2 EOR pilots advanced into commercial projects. Recently, other countries have ongoing offshore CO_2 EOR pilot projects. These pilot projects listed in Malone et al. (2014) include:

i. Lula Oil Field, offshore Brazil
ii. Draugen/Heiden Oil fields and Don Valley Project, North Sea
iii. Persian Gulf oil fields, offshore Abu Dhabi
iv. Rang Dong Oil Field, offshore Vietnam
v. Dulang Oil Field, offshore Malaysia

DATA DESCRIPTION

This study analyzed data from the Atlas of Gulf of Mexico gas and oil sands – summary file for 2012 data, obtained from the U.S. Department of Interior, Bureau of Ocean and Energy Management (BOEM, 2014) http://www.data.boem.gov/homepg/data_center/gandg/gandg.asp. Only BOEM-

categorized, saturated and undersaturated oil sands were studied, neglecting non-associated gas sands in the Atlas.

According to the BOEM data description, offshore GoM "Sands" refers to conventional oil and gas reservoirs, and should not be misinterpreted as thick or heavy oil such as Canadian oil sands. Based on production volumes, the BOEM categorized each offshore sand as oil (O), gas (G) and combination sands (B).

In addition to the aforementioned parameters, the BOEM database included reservoir geology. Each reservoir was described according to its chronozone name, play type, field structure, and field trap. Chronozones represented include: Miocene, Pleistocene, Pliocene, and Cretaceous age sands. Play types covered in this study are: progradational, aggradational, retrogradational, fan, and fold belt. Oil field structures included: 1,270 shallow salt diapers (0 – 4000ft sub-seabed depth), 453 intermediate salt diapers (4000 – 10000ft sub-seabed depth), 261 deep salt domes (>10,000ft sub-seabed depth), 807 anticlines, 357 faults, 258 rollovers/growth faults, 115 salt ridges, 63 stratigraphic traps, 25 shale diapers, 10 thrust faults, 7 unconformities, 1 reef, and 1 rotation slump block (BOEM, 2014).

Figure 6 shows locations of the 3,598 offshore Gulf of Mexico oil reservoirs (sands) examined in this thesis.

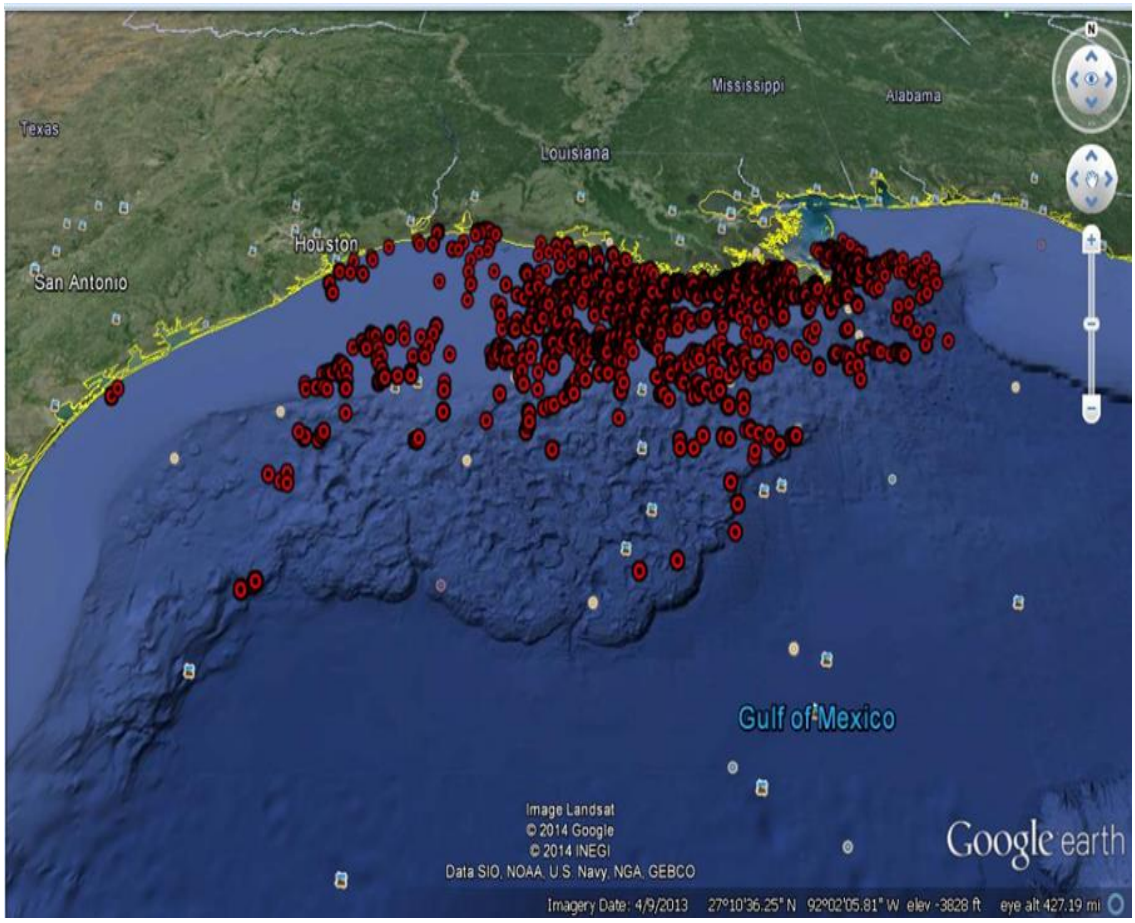

Figure 6: Map of offshore Gulf of Mexico study areas (created from Google earth using fusion tables)

Each offshore sand dataset is composed of 86 parameters that cover reservoir properties such as reservoir type, API and specific gravity, formation oil volume factor (B_{oi}), initial temperature (T) and pressure (P), oil in place (OIP), gas in place (GIP), cumulative oil production (N_p), cumulative gas production (N_g), well API number, sub-seabed and water depths, field structure and trap, play type, and gas-oil ratio (GOR).

For clarity of context, oil in place (OIP) and gas in place (GIP) in the BOEM data refers to original oil in place (OOIP) and original gas in place (OGIP), respectively. It was established that the GIP data only represent gas cap or free gas in saturated reservoirs and

nonassociated gas reservoirs. However, some data categorized under the undersaturated reservoir type reported significant GIP volumes. Further data analysis (presented below) explained the reasons for this occurrence.

Based on the BOEM sand definitions, all gas sands labeled G under sand type column of the BOEM data were excluded from this study. Analysis of the BOEM 2012 Atlas showed that an offshore oil sand may contain single or multiple reservoirs that are further categorized as saturated oil reservoirs (S), undersaturated oil reservoirs (U), and nonassociated gas reservoirs (N). Sands that contain multiple reservoirs were categorized based on the reservoir type that had the highest count. The next screening step eliminated only dataset labeled "N" under the reservoir type category. Thus, the remaining "S" and "U" reservoir type datasets were considered, even though some of these sands still contained nonassociated gas reservoirs. It was assumed that sands containing more gas reservoirs than oil reservoirs were poor CO_2 EOR candidates, irrespective of their gas to oil production rates. To further explain this BOEM reservoir type classification, an illustration of three oil sands is covered in the Eugene Island 330 field review.

A total of 10,860 reservoirs categorized under 3,598 sands were analyzed for reconnaissance-level geological storage potential of carbon dioxide in offshore oil reservoirs. The total number of reservoirs was obtained as a summation of the total reservoir count (TCNT) column of the BEOM atlas database. Following this reservoir CO_2 storage analysis, I applied additional screening criteria in the miscibility study. Based on the premise that offshore GoM oil sands are equivalent to conventional oil reservoirs, henceforth the term reservoir will be used in place of sands where appropriate.

CO_2 EOR OFFSHORE GOM CASE STUDY FIELDS

The Mississippi Canyon 807 (MC807) and Eugene Island 330 (EI330) fields were chosen as case study fields because they appeared in the ranking of several offshore field categories which included top proved oil reserves (table 1), top CO_2 EOR viable fields based on their OOIP, and field maturity. CO_2 EOR potential was calculated at 10 percent of the original oil in place. A summary of the geologic profile of the MC807 and EI330 fields is addressed below.

Table 1: Ten largest GoM OCS proved oil fields at year end 2009 (from BOEM, 2012)

Field Name	Original Proved Oil Reserves	Remaining Proved Oil Reserves	Water Depth
	(MMB)	(MMB)	(feet)
MC807—Mars-Ursa	1,326	387	3,335
MC778—Thunder Horse	733	684	6,078
WD 030	641	70	48
BM 002	536	7	50
EI 330	434	6	247
GC 640—Tahiti	414	391	4,312
GC 743-Atlantis	397	328	6,297
GI 043	384	16	140
MC 776 –N. Thunder Horse	383	347	5,665
GI 016	304	3	54

Mississippi Canyon 807 (MC807)

The MC807 oil field (also called Mars Ursa field) was discovered in 1989 in the Mississippi Canyon region, offshore GoM. It is located within the Ursa basin about 200km southeast coast New Orleans (figure 7). Mars Ursa 1,326 million barrel proven oil reserves

makes it the largest offshore GoM (table 1). The geology of the MC807 is characterized by anticline field structure and flank traps associated with salt or shale diapirs, as well as fan play type (BOEM, 2014). Sawyer et al. (2007), Binh et al. (2009) and Long et al. (2011) study reported that the Mars Ursa is composed of late Pleistocene sediments originating from the Mississippi River drainage system deposited about 70,000 years ago. According to Sawyer et al. (2007), the Mississippi river system was fed by the following four canyon channel levee systems: Young timbalier canyon (Mississippi Canyon), Old timbalier canyon, Southwest pass canyon, and Ursa canyon.

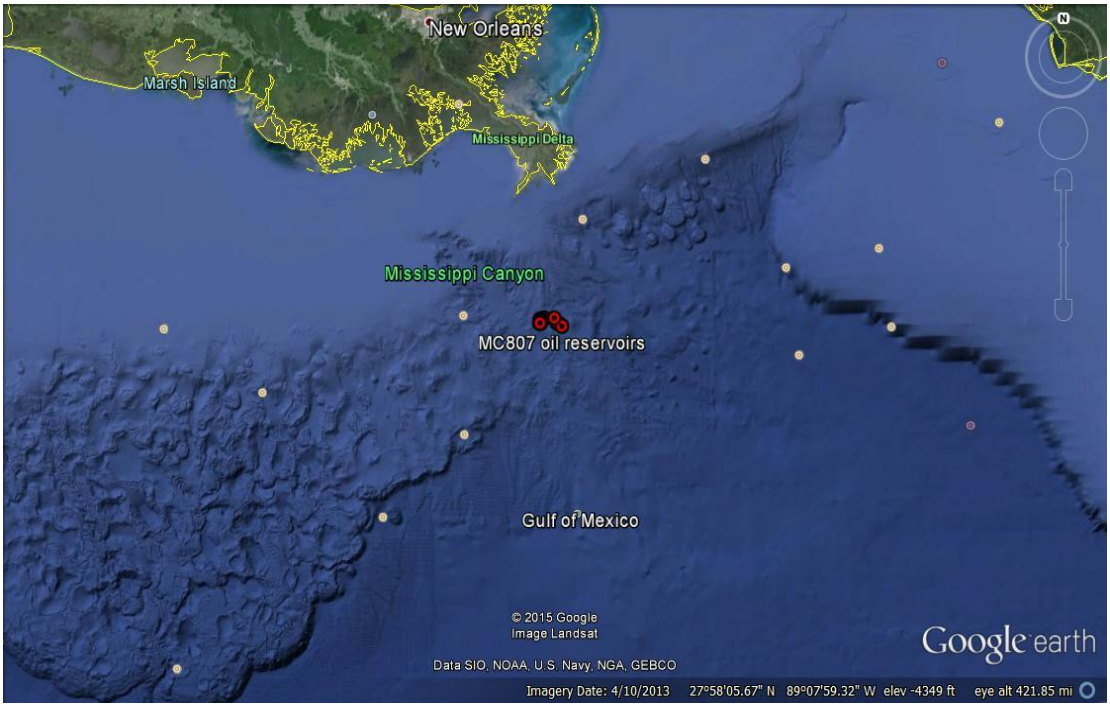

Figure 7: Location of MC807 oil reservoirs in the Mississippi Canyon (created from Google Earth using fusion tables)

The Sawyer et al. (2007) account of the depositional system of MC807 and its stratigraphic succession is depicted in figure 8, an interpreted seismic cross section showing a graphical representation of its depositional elements. The decreasing age order

of these depositional systems is as follows: (a) blue unit (b) canyon channel-levee (c) southwest pass canyon channel-leeve system and (d) mass transport deposits. They also reported that "*the Ursa region is bounded to the west by the Mars Ridge, a prominent north-south–trending bathymetric high that is the bathymetric expression of a buried channel-levee system. Eastward from the Mars Ridge, the sea floor slopes down to a zone of mass-transport deposits, including one failure described as one of the largest submarine mass transport deposits in the world*" (Sawyer et al., 2007).

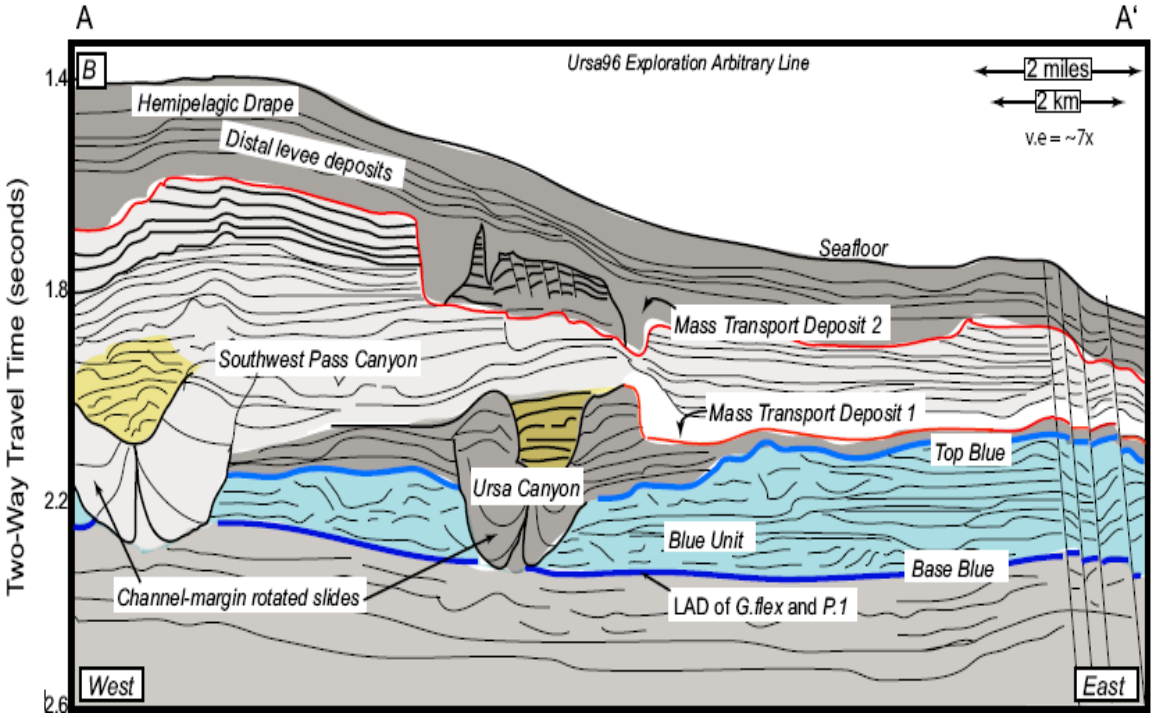

Figure 8: Mars Ursa interpreted seismic cross section A-A′ showing depositional elements and key surfaces (from Sawyer et al., 2007)

"Light and dark gray represent mud-rich levees and hemipelagic drape, and yellow represents sand-rich channel fill. The blue unit (light blue) is composed of sand and mud. Mass transport deposits have occurred in the mud-rich deposits above the blue unit. Detachment surfaces are colored red."

Eugene Island 330 (EI330)

The Eugene Island field contains multiple oil-bearing structural "blocks", one of which is the case study field Block 330 (with field code name EI330). Based on its remaining proven oil reserves and water depth as stated in BOEM (2014), the EI330 is considered a mature shallow water field. The Eugene Island 330 geology described here is based on works of Alexander and Flemmings (1995), Lin & Nunn (1997) and Joshi et al. (2012). They described the Eugene Island field as an elliptical shaped minibasin located on the outer continental shelf of GoM, approximately 270 km southwest of New Orleans. Its Pliocene–Pleistocene age siliciclastic sediments were deposited within its 20 x 15 km surface area. Joshi et al. (2012) describes the evolution of hydrocarbon reservoirs in the EI330 field:

> "*The basin formed as a result of deltaic sediment loading that caused underlying late Miocene-age salt to flow into adjacent areas. The evacuated salt left a topographic low at the surface that received sediments from the advancing delta. The evacuating salt formed four major fault zones along the borders of the basin: normal listric growth faults in the north and northeast and antithetic faults in the south and west. Motion along the growth faults produced rollover anticlines in the downthrown blocks that served as the principal traps for hydrocarbons*" (p. 55).

Figure 9 shows the following structural and stratigraphic evolution phases described in Alexander and Flemmings (1995) and Joshi et al. (2012).

i. **Early prodelta**: Figure 9-A represents the prodelta phase. During the early prodelta phase, turbidite, shale and sand were deposited on a Miocene salt sheet. Reservoirs formed in this phase are mostly over pressured such as the Lentic oil sand.

ii. **Intermedial proximal deltaic phase:** Presented in figure 9-B. is the deltaic phase. It was formed by alternate deposition of sand and mud in distributary channel, channel-mouth bar, and delta-front environments. Reservoirs formed during this phase are moderately over pressured.

iii. **Late fluvial phase**: Figure 9-C shows the fluvial phase. Reservoirs in this phase formed as a result of southward progradation of the deltaic system in shallow water. These reservoirs were described as hydrostatic pressured.

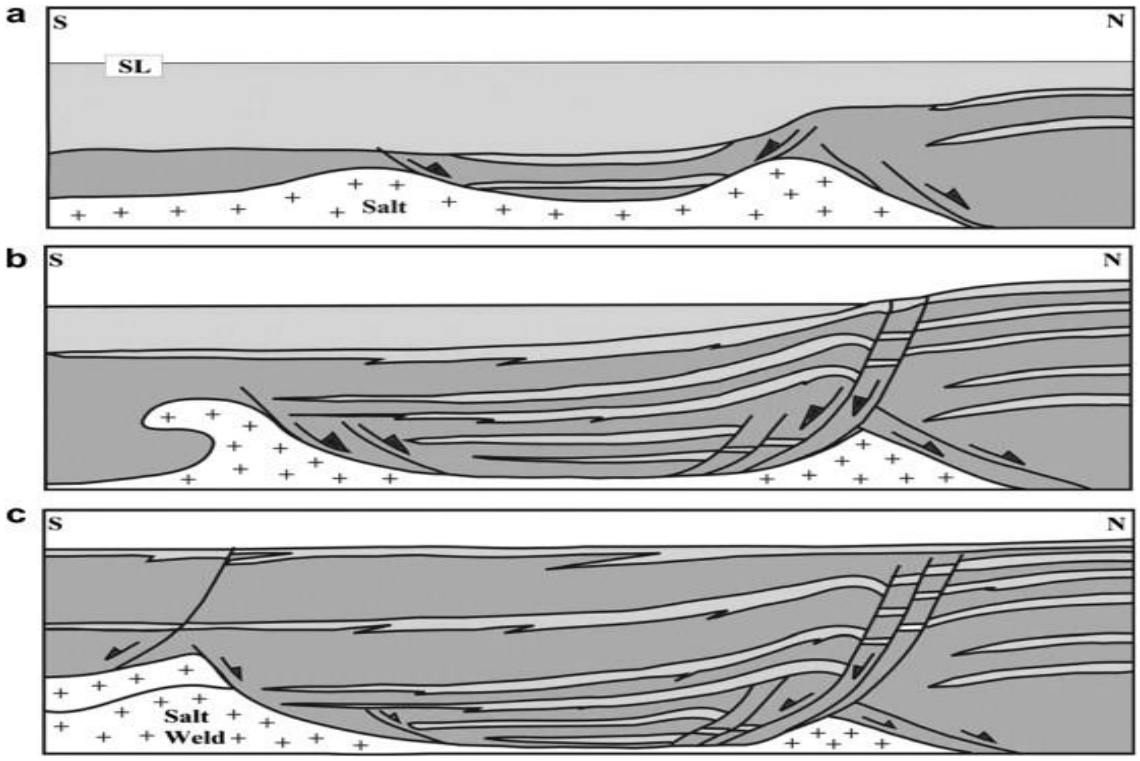

Figure 9: Three evolution phases of Eugene Island Field 330 from >2.8Ma to the present time (from Alexander & Flemmings, 1995)

The cumulative oil and gas production for the entire EI330 field was approximately 432 million barrels and 1.8 Mcf respectively. After omitting gas sands (labelled G under sand type column of the BOEM Atlas), the EI330 case study dataset contained 63 saturated

oil reservoirs, 110 undersaturated reservoirs, and 30 nonassociated gas reservoirs contained in 43 oil sands. In the BOEM Atlas, each oil sand has a unique sequence number (SN) that stays the same regardless of any changes or modification to the database. The first example, *0341_EI330_3800* with unique sequence number 76354, is a dataset for an oil sand that contains three undersaturated reservoirs. Because SN_76354 contains only undersaturated reservoirs, it was therefore classified as U under the reservoir type column of the BOEM database. Undersaturated reservoirs are above bubble point pressure and have no gas cap. Hence, the GIP value for SN_76354 was zero because it did not contain a saturated or nonassociated gas reservoir. The next example is oil sand 0981_EI330_OI2 with unique sequence number 81120 that contains eight reservoirs (six undersaturated, one saturated and one nonassociated gas reservoir). SN_81120 is classified as U reservoir type because undersaturated reservoirs outnumber other reservoir types in this sand. However, although SN_81120 is classified as a U reservoir, its GIP was computed because it was calculated from the gas cap of the comprising saturated and nonassociated gas reservoirs. This is in contrast with the first example that was similarly classified as a U reservoir type oil sand. The third example has a unique sequence number 79684, which represents oil sand 0961_EI330_L. Sand 0961_EI330_L contains 15 reservoirs (eight saturated, six undersaturated, and one nonassociated gas), and because the saturated reservoir outnumbered other reservoir types, this oil sand was classified as saturated reservoir type (S). Similar to the preceding example, GIP data for sand 0961_EI330_L was obtained from the gas cap of the comprising saturated and nonassociated gas reservoirs.

RECONNAISSANCE-LEVEL CO_2 STORAGE POTENTIAL AND EOR

Using the quick look storage potential (QLSP), adapted from Nunez-Lopez et al., (2008), I estimated sub-seabed reservoir storage capacity based on reservoir production profile, and oil and CO_2 formation volume factors. This capacity-estimation procedure does not consider reservoir geology, heterogeneity, or reservoir properties; hence it is a reconnaissance-level estimate. This level of capacity estimation is appropriate for the application used in this study. Many U.S. and international research efforts are underway to more accurately predict CO_2 storage capacity of onshore and sub-seabed geologic reservoirs. The QLSP equations applied in this section were published in the Nunez-Lopez et al. (2008) onshore study, but were modified in this study to fit the offshore GoM terrain. The only QLSP equation modification was decreasing the CO_2 flood recovery rate to 10% of OOIP. This assumption was based on offshore GoM site specific factors such as well spacing. The incremental oil that would be recovered (I_o) from CO_2 flooding was obtained for each reservoir; calculated as 10% of OOIP (Equation i). The QLSP was estimated from an equation by Nunez et al. (2008) (eq. ii)

$$\mathrm{Io} = \mathrm{OOIP} \times 0.1, \quad \text{..... (i)}$$

Equation (ii) estimates the QLSP before CO_2 EOR.

$$QLSP\ (metric\ tons) = 0.05259 \times Np\frac{Boi}{BCO2}, \quad \text{..... (ii)}$$

Where N_p = cumulative oil produced

B_{oi} = Oil formation volume factor

B_{CO2} = Estimated CO_2 formation volume factor

0.05259 is the conversion factor from Mcf to metric tons

N_p and B_{oi} were provided in the BOEM offshore GoM atlas database, while Jarel et al. (2002) empirical equation was used to estimate B_{CO2}.

To estimate the storage potential after CO_2 EOR, the result derived from equation (ii) was multiplied by a factor of 1.1, as in eqn. iii. This factor of 1.1 represents the initial storage capacity plus ten percent vacuum created from extraction of the incremental oil, thus a ten percent increase of CO_2 storage potential after EOR.

$$QLSP_{EOR} = QLSP \times 1.1, \quad \text{..... (iii)}$$

These equations calculate reconnaissance-level CO_2 volume for storage in sub-seabed geologic strata both before and after CO_2 EOR. Table 2 summarizes the offshore GoM QLSP analysis for 3,598 oil reservoirs (sands) analyzed in this study

Table 2: Storage capacity based on a quick look CO_2 storage assessment for the case study offshore GoM reservoirs

QLSP Assessment	Total CO_2 in Metric Tons
Estimated CO_2 QLSP before EOR	2, 293, 846, 297
Estimated CO_2 QLSP after EOR	2,523, 230, 962

MISCIBLE CO_2 EOR

Holm (1986) defines miscibility as: "*the physical condition between two or more fluids that will permit them to mix in all proportions without the existence of an interface.*" Miscible conditions have technical and economic advantages that maximize residual oil displacement. Carbon dioxide, hydrocarbon gas, nitrogen and flue gas are suitable solvents for gas EOR, which is implemented after exhausting primary recovery and water flood mechanisms. Nitrogen requires higher pressure to attain miscibility when compared to CH_4 or CO_2 floods (Sebastian et al., 2005). Vahidi et al. (2007) suggested that nitrogen gas flooding is preferred for immiscible EOR conditions. Miscibility requirements have

necessitated several studies that addressed reservoir conditions for successful miscible CO_2 flooding. Temperature, flooding pressure, reservoir pressure, depth and API gravity are among critical factors that influence CO_2 EOR. CO_2 is injected as a supercritical fluid to increase the capillary number and consequently improve displacement efficiency. CO_2 flood also reduces oil viscosity, thus improving sweep efficiency and mobility ratio (Bondor et al. 2005).

The two ways to achieve miscibility in a reservoir are: first contact miscibility and multiple contact miscibility. The following summary, describes these miscibility types as reported in Holm & Josendal (1974), Dumore et al. (1984), Stalkup (1987), Johns et al. (1993) and Juttner (1997). In first contact miscibility (FCM), the injected gas mixes directly with reservoir oil to form a single homogenous phase fluid. Intermediate gases (C_2 to C_6) – such as ethane, propane, butane - or liquefied petroleum gas are considered most suitable solvents for FCM (Juttner, 1997). Although FCM is technically the simplest way to achieve miscibility, its high operation cost makes it unattractive to operators. Multiple contact miscibility (MCM), as the name implies requires multiple contacts for the injected gas to overcome interphase tension with the reservoir oil. CO_2 solvent undergoes MCM through in-situ mass transfer of light to intermediate components of the reservoir oil in multiple phases. There are two processes associated with MCM: (i) vaporizing gas drive and (ii) condensing gas drive. Both processes involve the transfer of light to intermediate components to or from the reservoir oil respectively. In vaporized gas drive, intermediate gas components (such as ethane in the reservoir oil) enrich the CO_2 solvent which consequently reduces the MMP. Condensing drive (also referred to as enriched gas drive) involves transfer of intermediate components from gas phase into reservoir oil, and thus enriches the oil. Another peculiar mechanism combines condensing and vaporizing gas drives (CV) as described in Ahmadi and Johns (2011) and Johns et al. (1993). This

miscibility type occurs when intermediate components in the oil or solvent gas are insufficient to develop miscibility independently but can achieve miscibility under a combined enrichment transfer from oil to gas or vice versa until miscibility develops between the trailing edge and displacement front. Enriched gas drive mechanism enhances the CO_2 with other gas components that reduce MMP prior to injection.

Oil composition is considered another key factor in miscibility evaluation because of the immediate effect of solution gas on miscibility or its potential impact through the life of the EOR project. Lighter hydrocarbons comprised mostly of methane and ethane compounds (C_1 and C_2). Methane and ethane show dissimilar reaction to miscibility because of their disparity in molecular weight. Methane decreases miscibility whereas ethane improves miscibility. According to a Weyburn (Canadian) reservoir study, the resulting decrease in MMP from ethane occurred at a lower rate than an equal volume of methane would theoretically increase MMP in the same oil (Dong et. al, 2000). Based on that same Weyburn study, it was found that a reservoir oil with a high ethane to methane ratio could offset the negative impact of methane on miscibility in CO_2 EOR. How ethane can potentially balance the negative impact of methane on CO_2 EOR could be considered in a future study.

Not all miscible reservoirs are candidates for commercial CO_2 EOR. Technical screening criteria are crucial for determining economic viability. Taber et al. (1997) illustrated some miscible and immiscible CO_2 flood screening guidelines as presented in table 3. In addition to these guidelines in table 3, Taber et al. (1997) assumed miscible EOR potential at 22% OOIP and immiscible EOR at 10% OOIP.

Table 3: CO_2 flooding technical screening guidelines (from Taber et al. 1997)

Technical Screening Guides		
	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>22	27 to 44
Viscosity, cp	<10	0.3 to 6
Composition	High percentage of intermediate hydrocarbons (especially C_5 to C_{12})	
Reservoir		
Oil saturation, % PV	>20	15 to 70
Type of formation	Sandstone or carbonate and relatively thin unless dipping.	
Average permeability	Not critical if sufficient injection rates can be maintained.	
Depth and temperature	For miscible displacement, depth must be great enough to allow injection pressures greater than the MMP, which increases with temperature (see Fig. 7 of Ref. 1) and for heavier oils. Recommended depths for CO_2 floods of typical Permian Basin oils follow.	
	Oil Gravity, °API	Depth must be greater than (ft)
For CO_2-miscible flooding	>40	2,500
	32 to 39.9	2,800
	28 to 31.9	3,300
	22 to 27.9	4,000
	<22	Fails miscible, screen for immiscible*
For immiscible CO_2 flooding (lower oil recovery)	13 to 21.9	1,800
	<13	All oil reservoirs fail at any depth
At <1,800 ft, all reservoirs fail screening criteria for either miscible or immiscible flooding with supercritical CO_2.		

Before commencing a CO_2 EOR project, several technical screening steps are considered and implemented. Different EOR screening methodologies are available in literature, however this study only considered screening methods as described in Taber & Martin (1983), Lake (1989), Taber et al. (1997), Damen et al. (2005), Dipietro et al. (2014), Kang et al. (2014a) Kang et al. (2014b). Taber et al. (1997) suggested a range of depth for API values that are 22° or greater based on the Permian Basin EOR screening. Figures 10 and 11 illustrate another screening method based on oil viscosity and reservoir depth as described in Taber & Martin (1983). They suggested that onshore CO_2 EOR is most suitable for homogenous reservoirs at a depth greater than 2000ft.

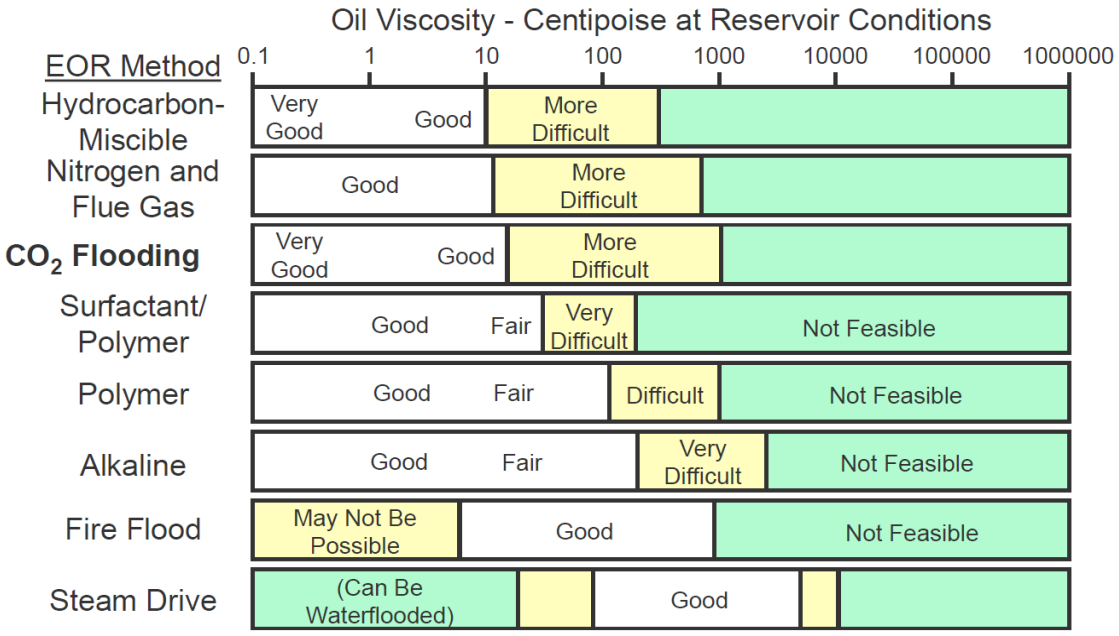

Figure 10: Comparison of optimal oil viscosity for various EOR methods (adapted from Taber & Martin, 1983)

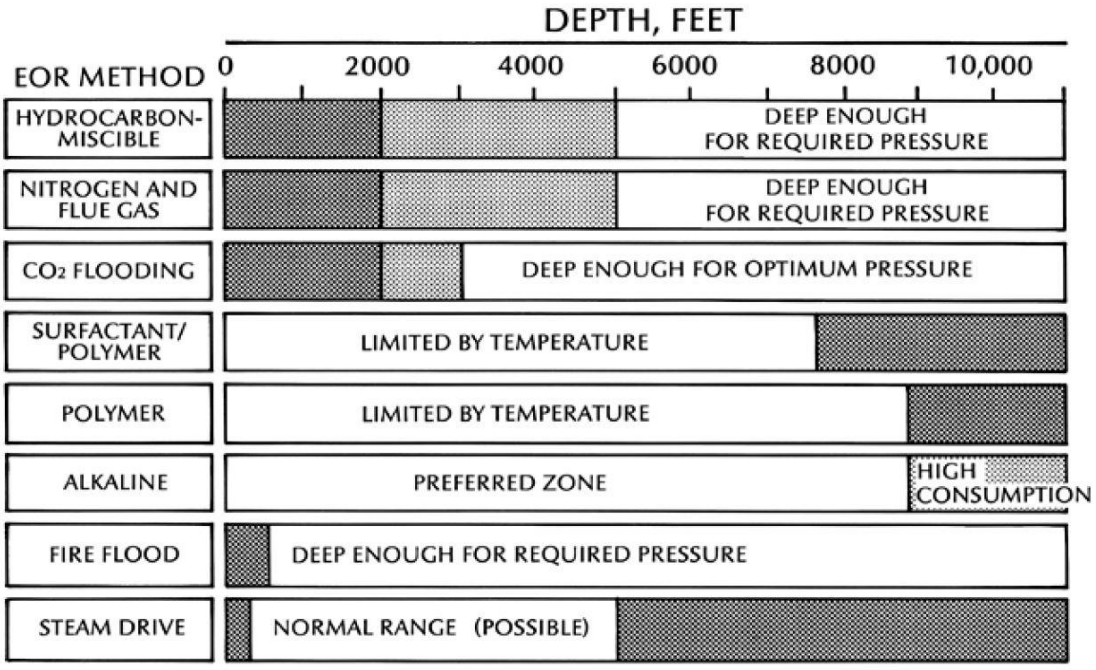

Figure 11: Comparison of optimal depth for various EOR methods (adapted from Taber & Martin, 1983)

Another critical technical criterion for gas EOR is that reservoir pressure must exceed the MMP (Yellig & Metcalfe, 1980), or in other words the pressure difference between the reservoir pressure and MMP is greater than one. For this study, reservoirs with pressure difference greater than 100psi were considered immiscible.

Minimum miscibility pressure may be obtained by experimental slim tube testing or mathematical models. Slim tube experiments are suggested to obtain the most accurate result because they involve experimenting on the specific reservoir oil, which makes this method expensive and time consuming. Holm (1986), and Elsharkawy et al. (1992) published detailed descriptions of MMP using slim tube testing. While Enick et al. (1988), Jaubert (1998), Jensen and Orr (2008), Johns et al. (2009), and Mogensen et al. (2009) described MMP mathematical methods for any gas mixture, MMP computation specific to CO_2 displacement was described in publications of Alston et al. (1985), Nunez-Lopez et al. (2008), and Johns et al. (2010). However, this study incorporated the equations for pure CO_2 MMP derived in Nunez-Lopez et al. (2008) and impurity factor in Sebastian et al. (1985) to derive an equation for impure CO_2 MMP. The impure CO_2 MMP was calculated as a product of impurity factor of CH_4 and MMP of pure CO_2. Impurity factor was derived for 5 – 50 mole percent CH_4 concentration in a CO_2 solvent stream on the basis that the initial solvent (pure CO_2) became contaminated with native CH_4 over time. The actual duration it would take for CH_4 to contamination the CO_2 solvent was not considered in this thesis however, Choi et al. (2013) suggested an average of 2 to > 10 mole percent increase of CH_4 in the recycled CO_2 injection stream, observed over a three year study period of the Cranfield CO_2 EOR project.

In this study, I investigate the effect of native CH_4 in recycled CO_2 with specific focus on its impact on miscibility using two screening methodologies. The first approach determines miscibility of studied offshore GoM oil reservoirs in the BOEM Atlas 2012

based on screening criteria that only eliminated gas sands and gas reservoir type (N). This method is referred to as "screening method A" in this thesis. The second approach combines the screening method A with additional screening criteria as described in Taber et al. (1997), Kang et al. (2014a) and DiPietro et al. (2014). The screening methods applied in this study, assumed the potential incremental oil recovery from CO_2 EOR was estimated at 10 percent of the original OIP. This study assumed locally sourced pure CO_2. The costs of capture, transportation and recycling were not analyzed in this study but they are available in literature in Malone et al. (2014) through the US DOE NETL study.

After initial pure CO_2 is injected in supercritical state, native hydrocarbon gases mix with CO_2 solvent. The hydrocarbon gases and CO_2 are subsequently co-produced with oil. In this study, it was assumed that only CH_4 gas was co-produced with CO_2. The CO_2-CH_4 mixture is re-injected or recycled multiple times thereby progressively increasing the volume of CH_4 in the injection solvent.

To begin, molecular weight (M_w) and MMP for pure CO_2 flood was derived using equations by Nunez-Lopez et al. (2008) (Eq. iv and v). Molecular weight was estimated as a function of the API data provided in the BOEM database.

$$Mw = \frac{7864.9^{(1/1.0386)}}{API} \quad \text{, ... (iv)}$$

Next, the M_w data obtained in Eq, (iv) was applied in Eq. (v) to calculate the minimum miscibility pressure for pure CO_2.

$$MMP_{pure} = -329.55 + (7.727M_w \times 1.005^T) - 4.377M_w, \text{ ..... (v)}$$

Where T is the initial reservoir temperature

Five to 50 mole percent CH_4 impurity factor is computed as a function of pseudocritical temperature (T_{pc}) of CH_4 and CO_2 mixture; and the T_{pc} is derived using

critical temperature, as well as mole percent concentration of both gases. To calculate impure MMP of varying mole percent contamination of CH_4 in the CO_2 stream, a model for 5, 10, 20, 30, 40, and 50% mole concentration CH_4 in CO_2 was derived using an impurity factor (F_{imp}) from equation numbers (vi) and (viii) adapted from Sebastian et al. (1985).

$$T_{pc} - T_c = Y_c T_c + (1 - Y_c) T_{c1} - T_c, \quad \text{..... (vi)}$$

Where:

$T_{pc} = \sum_i T_{ci} Y_i$ is the pseudo-critical temperature of the mixture

T_c is the critical temperature of CO_2 = 87.9°F or 304.21K

Y_c is the mole fraction of CO_2 in the solvent

T_{c1} is the critical temperature of CH_4, = - 116.5°F or 190.65K

Equation (vi) is simplified as:

$$T_{pc} - T_c = [Y_c T_c + Y_{c1} T_{c1}] - T_c, \quad \text{..... (vii)}$$

Where mole fraction of CH_4, $Y_m = (1 - Y_c)$

$$\therefore F_{imp} = 1.0 - (2.13 \times 10^{-2})(T_{pc} - T_c) + (2.51 \times 10^{-4})(T_{pc} - T_c)^2 - (2.35 \times 10^{-7})(T_{pc} - T_c)^3, \quad \text{..... (viii)}$$

These equations were applied to derive the impurity factors for CH_4 in CO_2 calculated below;

For 95 mole percent CO_2 and 5 mole percent CH_4

$$T_{pc} - T_c = [(304.21 \times 0.95) + (1 + 190.56 \times 0.05)] - 304.21$$

$$= 298.53 - 304.21$$

$$= -5.68K$$

$$F_{imp} = 1.0 - (2.13 \times 10^{-2}) - 5.68 + (2.51 \times 10^{-4})(-5.68)^2 - (2.35 \times 10^{-7})(-5.68)^3$$

$$= 1.13$$

The impurity factors for the specified mole fractions of CH_4 in CO_2 are presented in table 4.

Table 4: Methane impurity factor correlation with carbon dioxide

yCH_4	yCO_2	Tpc (K)	Imp. Factor CH_4
0	1	304.21	1.00
0.05	0.95	298.53	1.13
0.10	0.90	292.85	1.27
0.18	0.82	283.77	1.54
0.20	0.80	281.49	1.62
0.30	0.70	270.14	2.03
0.40	0.60	258.78	2.51
0.50	0.50	247.43	3.06

These impurity factors were applied to calculate the MMP for impure CO_2 of each reservoir by multiplying the minimum miscibility pressure of pure CO_2 by the corresponding mole percent CH_4 impurity factor (Eq. ix).

$$\frac{MMP_{impure\ co2}\ (P_{ic})}{MMP_{pure\ CO2}(P_c)} = Impurity\ Factor\ (F_{imp})$$

$$P_c \times F_{imp} = P_{ic}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(ix)}$$

Where P_c and P_{ic} are minimum miscibility pressure for pure CO_2 and impure CO_2 stream respectively.

It was observed that MMP increased with increased CH_4 concentration in the CO_2 stream. The linear relationship of pure and impure CO_2 MMP is presented in figure 12. The

blue dots in figure 12 represent data points extracted from the study spreadsheet, representing over 3,000 reservoirs.

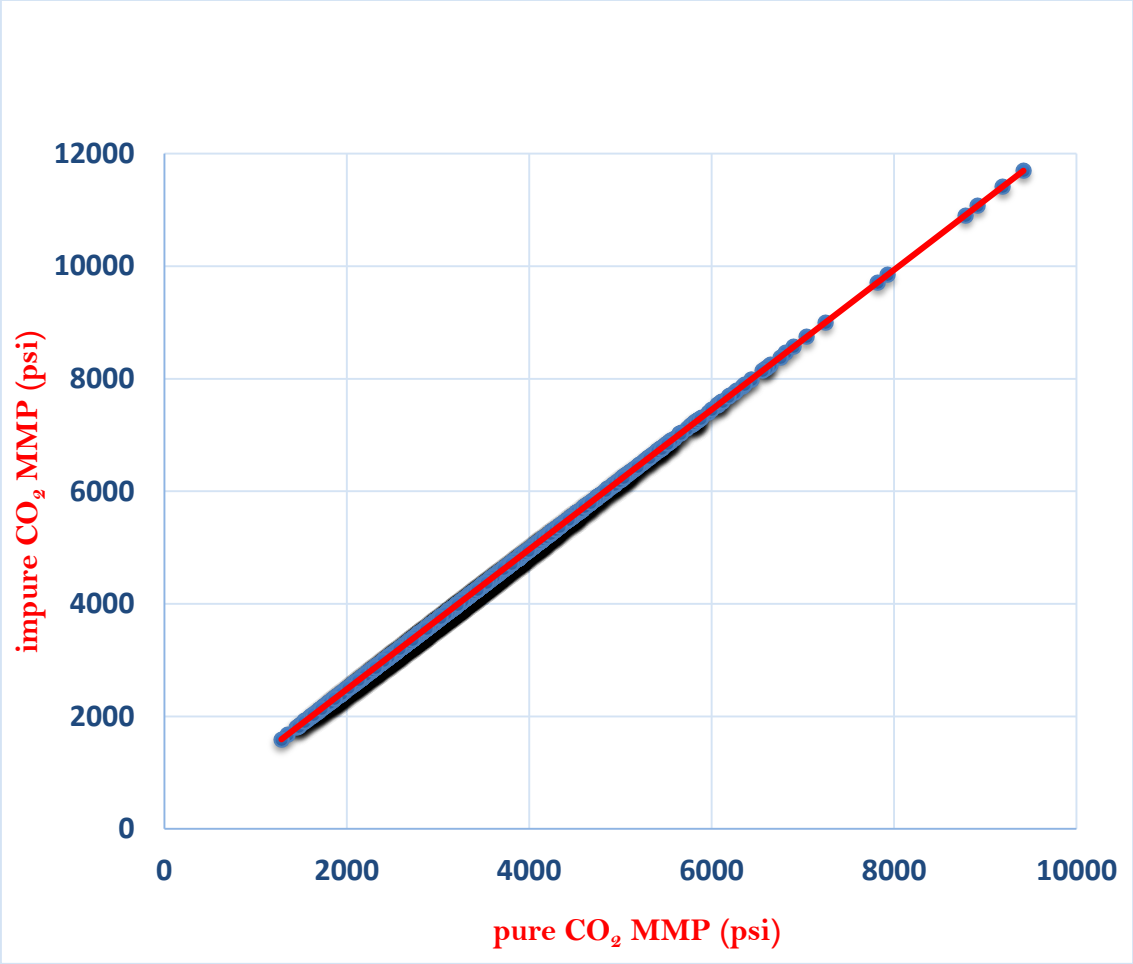

Figure 12: Comparative analysis of MMP in pure and impure CO_2 steam based on 18 mole % CH_4 impurity

Applying screening method A to the EI330 field eliminated 14 gas reservoirs. The production profile of the remaining 43 oil reservoirs comprised of 17 saturated reservoirs and 26 undersaturated reservoirs is presented in table 5.

Table 5: EI330 oil reservoir production data (compiled from the BOEM 2012 Atlas database)

EI330 field	Saturated reservoir	Undersaturated reservoir	Total reservoirs
Number of reservoirs	17	26	43
OOIP (bbl)	677,481,115	231,378,811	908,859,926
OGIP (Mcf)	730,400,322	26,881,603	757,281,925
Cumulative oil production (bbl)	309,625,187	82,959,401	392,584,588
Cumulative gas production (Mcf)	753,180,009	93,903,176	847,083,185
Cumulative BOE (bbl)	443,642,987	99,668,155	143,311,142

Oil saturation data was not reported in the BOEM 2012 Atlas but was available in another BOEM database, titled Maximum Efficiency Rate (MER) database. Residual oil saturation was only considered in the EI330 case study field but not considered in other fields due to lack of data. The BOEM MER data reported various oil saturation values for the EI330 that ranged from 0.40 – 0.85 per reservoir. Approximately 39 million barrels of oil is estimated as the potential incremental CO_2 EOR for the EI330 field (assuming 10% of OIP in table 5). The minimum miscibility pressure for each reservoir was obtained using Eq. (ii). The MMP results showed that all reservoirs were miscible with pure CO_2 except reservoir 0541_EI330_GA2 (unique sequence number 77842) analyzed in table 6.

Table 6: Immiscible reservoir data for 0541_EI330_GA2 (compiled from the BOEM 2012 Summary file for oil and gas sands database)

Sand Name	0541_EI330_GA2
Reservoir type	**Undersaturated**
API	**29°**
Initial Temperature (T)	**130°F**
Initial Pressure (P)	**2,097psi**

$$Mw = \frac{7864.9^{(1/1.0386)}}{API} = \frac{7864.9^{(1/1.0386)}}{29} = 220.22$$

Next, the reservoir MMP was obtained using equation (v)

$$MMP_{pure} = -329.55 + (7.727M_w \times 1.005^{T}) - 4.377M_w$$

= 1, 999psi

$\Delta P = P - MMP$, …….. (x)

Where P = Initial pressure

ΔP = pressure differential

This study assumed $\Delta P > 100$ as a condition for miscible CO_2 flood. Applying equation (x) showed that 0541_EI330_GA2 reservoir is best suitable for an immiscible flood.

$\Delta P = P - MMP$

= 2,097 - 1,999

= 98 psi (considered immiscible based on the screening criteria in this thesis)

The remaining 42 reservoirs had ΔP values greater than 100, and these were considered candidates for miscible CO_2 EOR. Table 7 shows ΔP of a random selection of EI330 reservoirs.

Table 7: Pressure differential for methane impurity in carbon dioxide solvent in a random selection EI330 reservoirs

SN	SAND_NAME	0% CH_4	10% CH_4	20% CH_4	30% CH_4	40% CH_4	50% CH_4
80831	0981_EI330_M2_3_4	2,300	1,246	-257	-2,190	-4,630	-7,558
79684	0961_EI330_L	2,319	1,234	-314	-2,305	-4,818	-7,834
80858	0981_EI330_N	2,831	1,697	80	-2,000	-4,625	-7,775
79404	0961_EI330_KE1	2,148	1,243	-47	-1,705	-3,800	-6,312
81469	0981_EI330_OI1_2_Q	3,381	2,146	385	-1,879	-4,737	-8,167
77637	0541_EI330_E	1,602	909	-78	-1,348	-2,951	-4,874
77843	0541_EI330_GA5	1,347	760	-76	-1,152	-2,509	-4,139
78541	0561_EI330_IC2	1,762	1,019	-39	-1,401	-3,120	-5,182
79243	0961_EI330_JD1	2,050	1,102	-250	-1,988	-4,182	-6,816
79510	0961_EI330_KE2	2,373	1,497	247	-1,360	-3,388	-5,822
78328	0541_EI330_HB3	2,025	1,404	519	-619	-2,056	-3,781
81120	0981_EI330_OI2	3,191	1,973	237	-1,996	-4,814	-8,197
413265	0541_EI330_HB1B2	1,500	913	77	-999	-2,356	-3,986
76411	0541_EI330_5100	1,563	1,010	221	-793	-2,074	-3,611
77842	0541_EI330_GA2	1,052	488	-317	-1,351	-2,658	-4,225

Each EI330 reservoir had equal water depth of 248 feet but different sub-seabed depth, API gravity, initial temperature and pressure.

A sensitivity analysis of the undersaturated and saturated EI330 reservoirs provided in figures 13 and 14 respectively showed that saturated reservoirs were more tolerant to CH_4 contamination in a CO_2 stream. However, this finding is not conclusive but may be theorized in future studies.

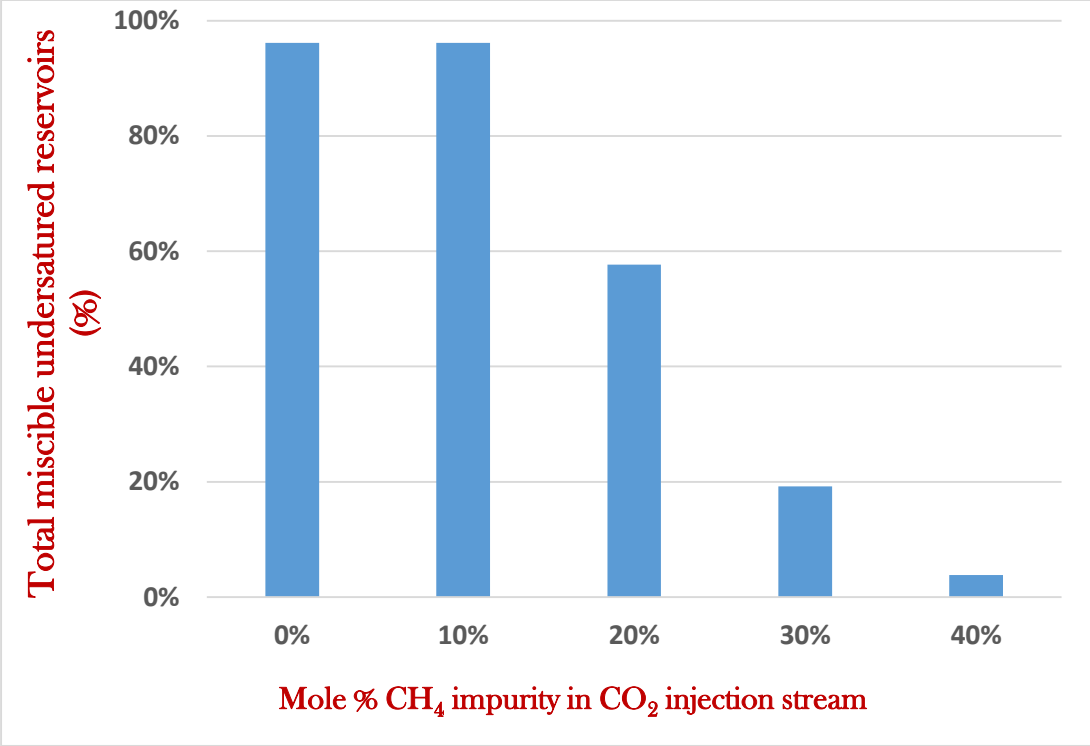

Figure 13: Undersaturated reservoirs and miscibility: EI330 case study field

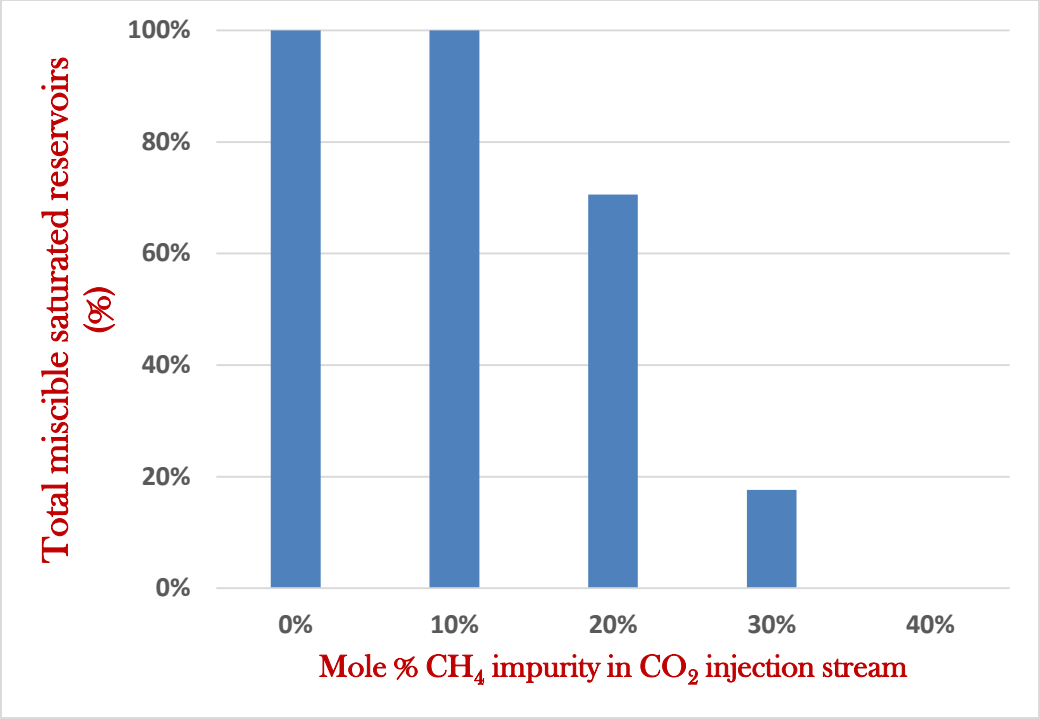

Figure 14: Saturated reservoirs and miscibility: EI330 case study field

Analysis of the MC807 case study field revealed that 27 reservoirs were situated in this field. Of these 27 reservoirs, 23 are undersaturated oil reservoirs and 4 are non-associated gas reservoirs. There are no gas sands in the MC807 field, although the field contains four non-associated gas reservoirs. Only one oil sand was categorized under the N reservoir type. According to the MC807 production profile, four of the undersaturated reservoirs are yet to commence production. The 2012 cumulative oil production for the entire MC807 field was 1.04 billion barrels of oil and 1.35 billion Mcf gas, while 4.8 billion barrels is the estimated OOIP. The miscibility assessment of the MC807 field revealed its high tolerance to CH_4 contamination, which reflected up to 50 mole percent CH_4 impurity in the CO_2 solvent (figure 15). Probable reasons for this high tolerance to CH_4, reflected in figure 15, could be as a result of the dominant medium to light oil in the field combined with its fan play type. It was observed that the API gravity of all the reservoirs were 22^o or

greater. The relationship between miscibility and play type was further evaluated; the outcome is reported in the next section.

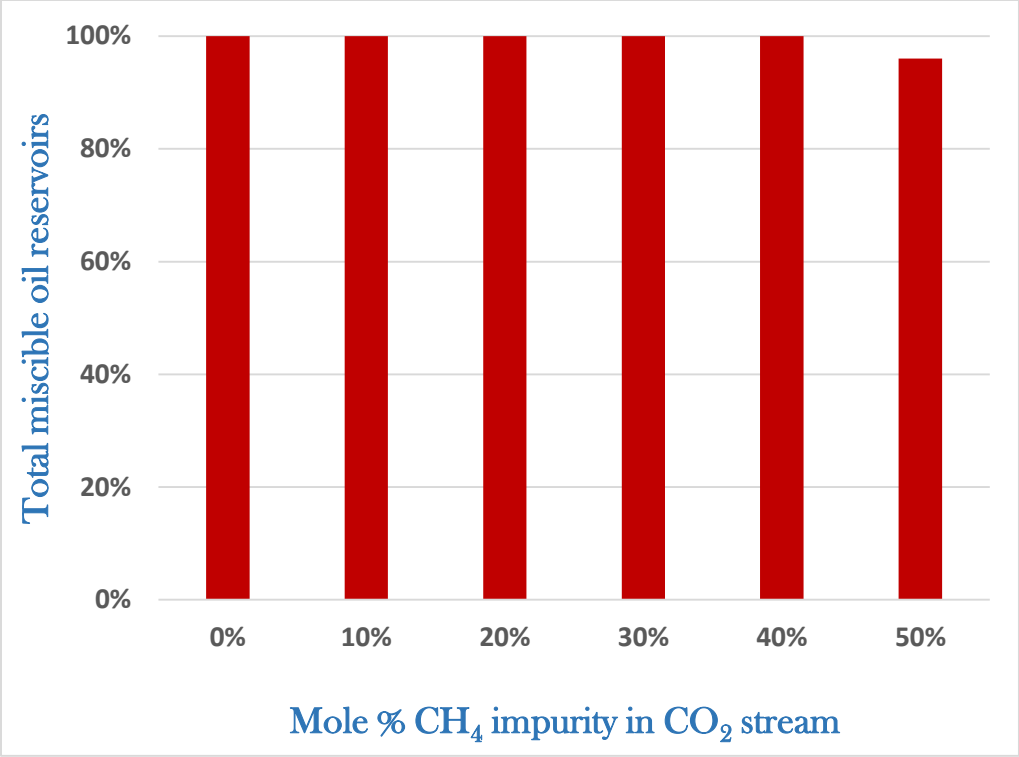

Figure 15: Miscibility study for impure CO_2 EOR: case study MC807 field

MISCIBILITY PROFILING AND CORRELATION

The methodologies described in the MC807 and EI330 field miscibility assessment were ultimately applied to the 3,598 offshore GoM reservoirs under review. Figure 16 shows the miscibilty trend of the offshore GoM study area, where CH_4 is considered as the main impurity in the CO_2 injectant. Almost all 3,598 offshore GoM reservoirs analyzed were miscible with pure CO_2. To sustain miscibility in at least 70 percent of these reservoirs, study results revealed that CH_4 impurity in recycled CO_2 solvent should be NO MORE THAN! 18 mole percent. The miscibility trend showed that when CH_4 impurity in the recycled CO_2 solvent increased from 10 to 20 mole percent, about 35% of these case study reservoirs converted from miscible to immiscible.

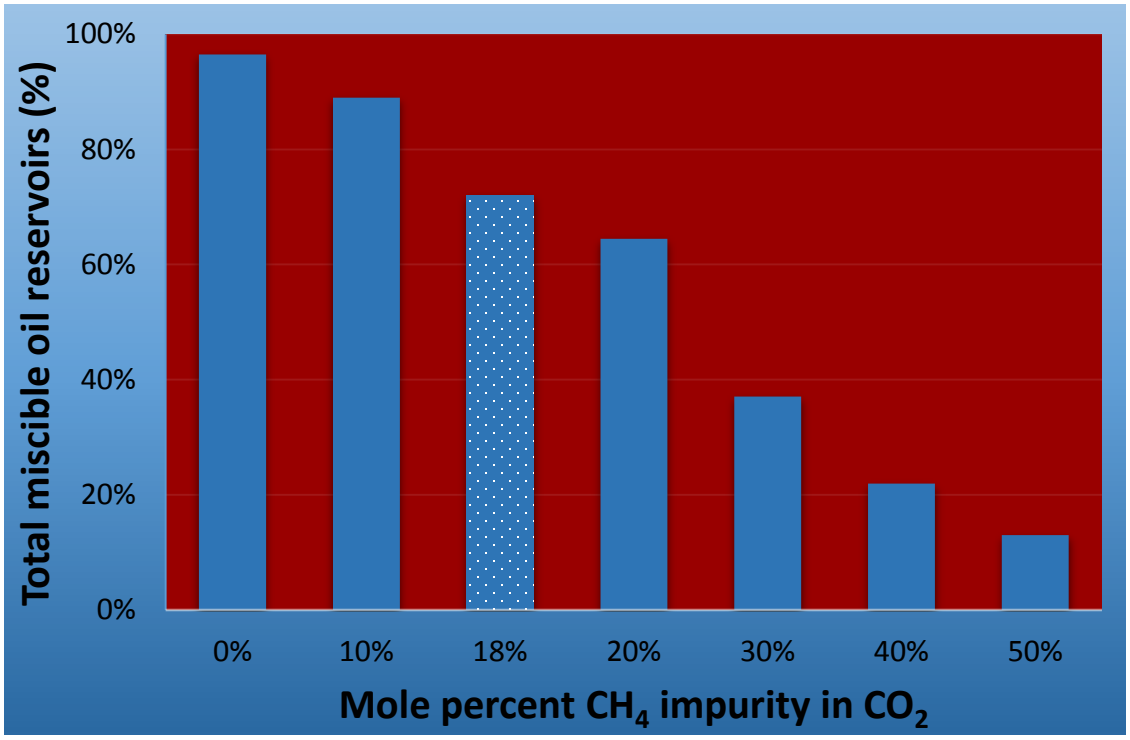

Figure 16: Decreased miscibility resulting from increased CH_4 impurity in CO_2 solvent obtained for 3,598 offshore GoM reservoirs

Based on these results 18 mole percent CH_4 impurity limit in the CO_2 injection solvent was established as the maximum amount that would allow these offshore GoM oil reservoirs to maintain their miscibility level (figure 16). Further miscibility analysis conducted based on the published BOEM data parameters included a correlation of miscibility with API gravity, play type, and depth.

IMPACT OF API GRAVITY ON MISCIBILITY

Taber et al. (1997) considered API gravity in their technical evaluation of CO_2 EOR amenable reservoirs, and was thus included in the second screening method of this study. API gravity reflects crude oil classification which could range from extra heavy oil to light oil. Heavy oil has API less than 22.3^o; light oil is considered as having an API gravity greater than 31.1^o, while medium oil lies between these two categories. The MMP in equation (v) considers only molecular weight and temperature. Hence, because API gravity is inversely proportional to molecular weight, i.e. API increases as molecular weight decreases, increased API values resulted in a decrease in the MMP, and consequently an increase in miscibility (figure 17). The blue dots shown in figure 17 are actual API gravity data points computed in the study spreadsheet.

An analysis on the correlation of API gravity and MMP showed miscibility improved in light oils. About five percent of the offshore GoM study data under screening method-A which had API gravity less than 22^o were excluded from this analysis. The model applied in this analysis assumed up to 30 percent increasing API values at constant temperature. It was observed that at 25 percent increase in oil API gravity of the screened reservoirs, all reservoirs were miscible with pure CO_2 flood.

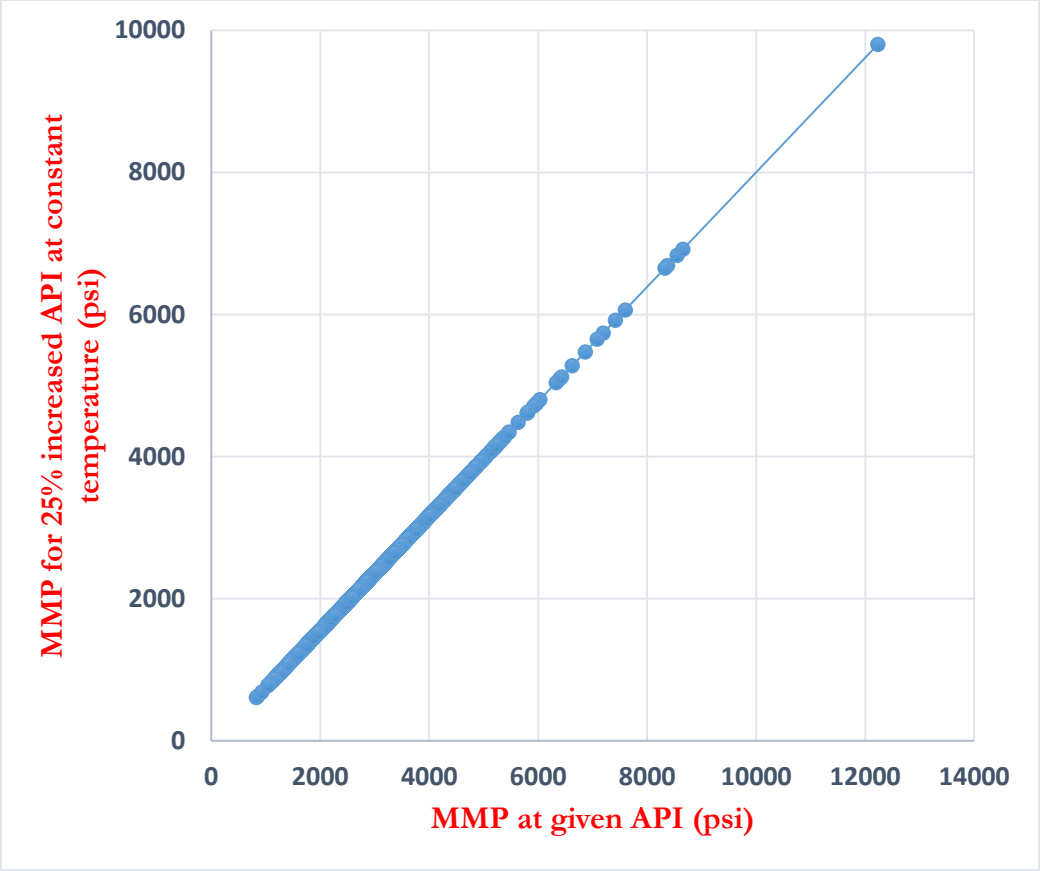

Figure 17: API correlation with MMP at constant reservoir temperature

MISCIBILITY AND DEPTH CORRELATION

The study data contained two depth parameters, water depth and sub-seabed depth. Reservoirs were sorted into five depth categories as shown in figure 18, starting with the minimum reservoir sub-seabed depth of 1,350ft.

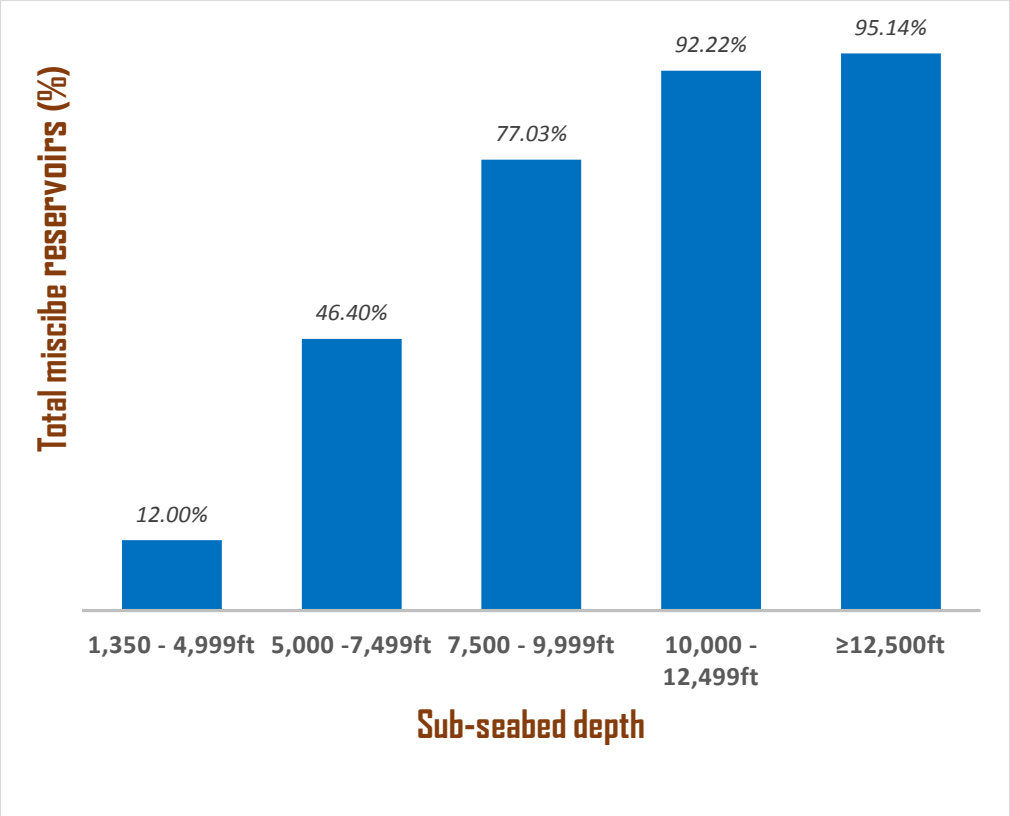

Figure 18: Sub-seabed depth correlation with miscibility for 18 mole percent methane impurity [$82CO_2 + 18CH_4$]

Further sub-seabed depth analysis revealed that reservoirs less than 2,475ft were poor candidates for miscible CO_2 EOR even when injected with pure CO_2 (only 18 oil sands were shallower than 2,475ft.).

Water depth only was considered in the second phase of the miscibility to depth analysis for up to 50 mole percent CH_4 impurity in the injected CO_2 solvent. At 40 mole percent CH_4 impurity, results showed over 80% of deep water reservoirs (water depths greater than 1,000ft) maintained miscibility. When the CH_4 impurity in these deep water reservoirs increased to 50 mole percent, about 76% of the reservoirs remained miscible. In contrast, shallow water reservoirs were less favorable to impure CO_2 flood. While all deep water reservoirs were miscible at the 18 mole percent impurity limit, only about 67% of

the shallow water reservoirs remained miscible at this CH_4 impurity limit. The third analysis of the miscibility to depth analysis considered the addition of water depth and sub-seabed depth (referred to here as total depth). Similar to the sub-seabed depth study, a range of the total depth was considered based on 18% CH_4 impurity threshold, as illustrated in figure 19. Reservoirs at less than 5,000ft were least tolerant to impure CO_2 EOR and deeper reservoirs were more amenable to miscible impure CO_2 EOR.

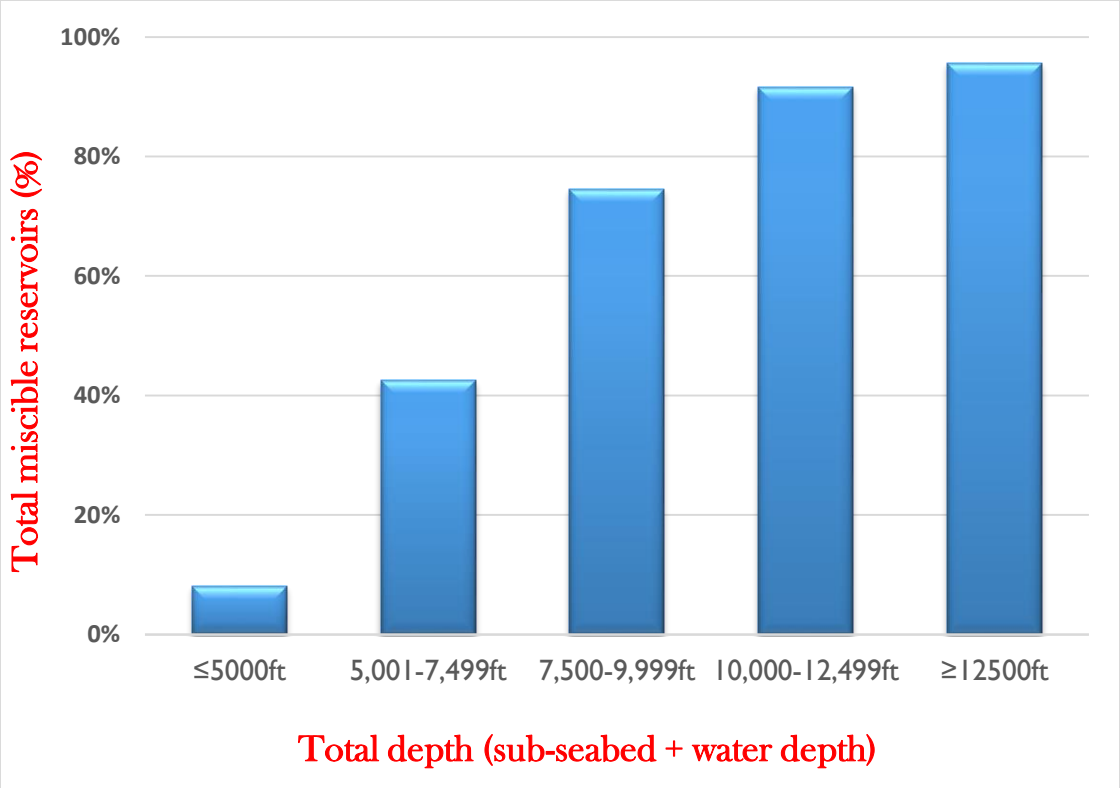

Figure 19: Analysis of total depth (sub-seabed +water depth) and miscibility for [$82CO_2 + 18CH_4$] mixture

MISCIBILITY CORRELATION WITH PLAY TYPE

An analysis of the role of hydrocarbon plays and their relationship with CH_4 impurity in CO_2 flood was another factor considered in this thesis. After applying screening

method A, the BOEM reservoir database mostly consisted of progradational and fan play types. The post screening play types represented are 2135 progradational, 1072 fan, 315 aggradational, 52 fold belt, and 22 retrogradational. Some oil fields were characterized by a single play type such as the MC807 that has only fan play type, while others had multiple play types such as the EI330 with a combination of aggradational, fan and progradational play types. All Mars Ursa (MC807) reservoirs illustrated earlier in figure 15 remained miscible when up to 40 mole percent CH_4 contaminated the CO_2 stream.

All play types under screening method A were evaluated at 18 mole percent CH_4 impurity limit. Figure 20 illustrates the outcome of the miscibility evaluation with 18 mole percent CH_4 impurity based on play type.

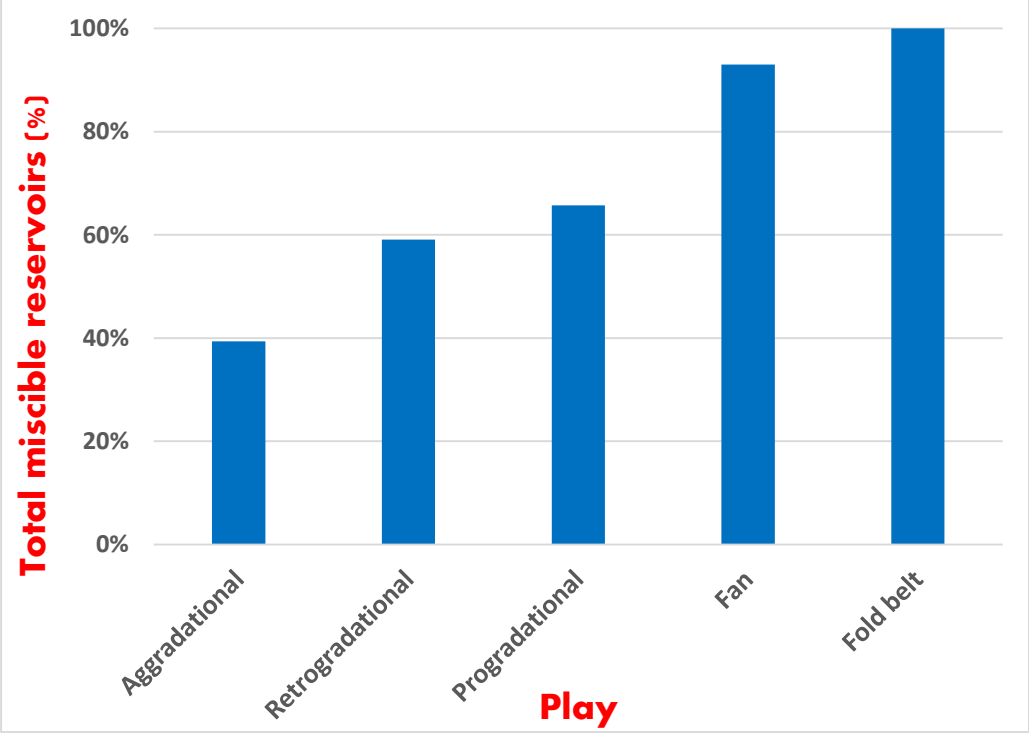

Figure 20: Analysis of play type and miscibility for impure CO_2 solvent: [$82CO_2 + 18CH_4$]

This outcome indicates that approximately 2,593 reservoirs or about 72% of the analyzed reservoirs remained miscible at 18 mole percent CH_4 impurity, based on their play profile. Impure CO_2 at 18 mole percent CH_4 showed fold belts and fan play were most tolerant to CH_4 impurity in CO_2 EOR. Further investigation to define reasons behind these play to miscibility outcomes are not covered in this thesis.

FUTURE STUDY

An important part of this study was to determine the degree CO_2 could devalue the CH_4 as a result of its transfer into native gas. Several methods were applied to evaluate this problem, however data limitations made it impossible to proceed further during the study period. It was established that the critical gas oil ratio for economically viable CO_2 EOR was strongly dependent on incremental oil and gas revenues assuming at least two EOR techniques are applied: CO_2 based gas EOR or any non-gas EOR. The incremental oil recovery was estimated to be 10 percent of OOIP; but limited data and time constraint made it impossible to estimate the corresponding gas production. During the economic analysis, it was decided that the critical GOR for economic viability might not be accurate without a comparative analysis of alternative gas EOR or non-gas EOR methods. Other contributing economic factors to be considered are CAPEX and OPEX of an amine CO_2 capture unit, and the cost of CO_2 scrubbing. Although further study is required on this topic, equations for economic viability were derived based on the available data (Eq xi and xii);

$$if\ Gas\ profit\ (\$) < Oil\ profit\ (\$), \quad \text{(xi)}$$

$$\therefore \frac{Gas\ profit}{Oil\ profit} < 1, \quad \text{(xii)}$$

where $$\frac{Gas\ profit}{Oil\ profit} = \frac{(Produced\ gas \times gas\ price) - gas\ OPEX - gas\ CAPEX}{(Produced\ oil \times oil\ price) - Oil\ OPEX - oil\ CAPEX}$$

If equations (xi) or (xii) are true, the corresponding oil reservoir is considered not economically viable for CO_2 EOR. Produced gas and oil above refer only to CO_2 EOR production. In some mature oil fields, oil CAPEX may have declined to zero prior to EOR.

REGULATORY AND LEGAL FRAMEWORK

Greenhouse gas (GHG) mitigation remains a global concern to environmentalists, policy makers, and the public. CO_2, the main GHG emitted from burning fossil fuels, can be sequestered or stored underground for long periods of time and be economically beneficial as an injection fluid in tertiary oil production. In search for climate change solutions, CCS has gained considerable importance in GHG mitigation.

On October 2011 the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly the Minerals Management Service (MMS), was replaced by the Bureau of Ocean Management (BOEM) and the Bureau of Safety Environmental Enforcement (BSEE) to administer the Outer Continental Shelf Lands Act (OCSLA). The US BOEM and BSEE under the authority of the US Department of Interior (DOI) have jurisdiction and are charged with regulating the OCS activities including offshore GS and EOR. Although separate agencies of the DOI, each agency has complimentary regulatory roles to oversee offshore economic resources and to enforce environmental health and safety best practices respectively. The BOEM regulations on oil, gas and sulphur are available in the code of federal regulation (CFR), as stated in Title 30 CFR Part 250 while the BSEE regulations are stated under Title 30 CFR Part 550. Both of these rules became effective on October 1, 2013. Subparts A and K of these rules may apply to offshore carbon dioxide geologic sequestration and CO_2 EOR, such as:

§550.119 Will BOEM approve subsurface gas storage?

"The Regional Supervisor may authorize subsurface storage of gas on the OCS, on and off-lease, for later commercial benefit. The Regional Supervisor may authorize subsurface storage of gas on the OCS, off-lease, for later commercial benefit. To receive approval you must:

(a) Show that the subsurface storage of gas will not result in undue interference with operations under existing leases; and

(b) Sign a storage agreement that includes the required payment of a storage fee or rental."

§250.118 Will BSEE approve gas injection?

"The Regional Supervisor may authorize you to inject gas on the OCS, on and off-lease, to promote conservation of natural resources and to prevent waste.

(a) To receive BSEE approval for injection, you must:

(1) Show that the injection will not result in undue interference with operations under existing leases; and

(2) Submit a written application to the Regional Supervisor for injection of gas.

(b) The Regional Supervisor will approve gas injection applications that:

(1) Enhance recovery;

(2) Prevent flaring of casinghead gas; or

(3) Implement other conservation measures approved by the Regional Supervisor."

§250.1165 What must I do for enhanced recovery operations?

"(a) You must promptly initiate enhanced oil and gas recovery operations for all reservoirs where these operations would result in an increase in ultimate recovery of oil or gas under sound engineering and economic principles.

(b) Before initiating enhanced recovery operations, you must submit a proposed plan to the BSEE Regional Supervisor and receive approval for pressure maintenance, secondary or tertiary recovery, cycling, and similar recovery operations intended to increase the ultimate recovery of oil and gas from a reservoir. The proposed plan must include, for each project reservoir, a geologic and engineering overview, Form BOEM-0127, and supporting data as required in §250.1167, 30 CFR 550.1167, and any additional information required by the BSEE Regional Supervisor.

(c) You must report to Office of Natural Resources Revenue the volumes of oil, gas, or other substances injected, produced, or produced for a second time under 30 CFR 1210.102."

LIMITATIONS/BARRIERS TO DEVELOPING LEGAL FRAMEWORK IN THE US

- Inadequate climate change legislation to encourage carbon capture and storage (CCS): US climate change laws are still in infancy. Enacting greenhouse gas

legislation into law would play a crucial role in CCS implementation for both onshore and offshore regions. The pioneering Sleipner and Snohvit CCS projects in the North Sea were implemented in response to the Norwegian government's climate legislation.

- Under-developed regulations: Anthropogenic CO_2 injection for the purpose of GS or EOR has only recently been recognized. Thus, existing BOEM and BSEE regulations for the US OCS do not comprehensively address large scale offshore CCS. Although some of its regulations are applicable to offshore geological storage, they are presently not sufficient to enforce CO_2 GS practices on operators.
- Price based regulatory mechanisms – Carbon reforms such as carbon credit and carbon tax motivated operators in Sleipner West field to inject CO_2 for offshore geologic sequestration to avoid paying about NOK 1 million per day an equivalent of about US$170,000 in emission fines (MITei, 2014). Carbon policy price mechanism would set a price on carbon emissions which would in turn positively impact climate mitigation.
- Non-price based regulatory mechanisms – Effective public awareness to offer confidence on the safety of CCS to human and environment health should be considered while developing the offshore regulatory framework. Offshore sub-seabed storage will be away from drinking water aquifers, which should eliminate public concern. Furthermore, awareness should be created to inform the public that offshore geological storage could be engineered to avoid negatively impacting aquatic habitats or the ocean in general.

DISCUSSION AND CONCLUSIONS

For over three decades, the US onshore oil fields have injected CO_2 for EOR, while offshore CO_2 EOR is still emerging. Furthermore, the only offshore CO_2 geological storage (GS) are the Norwegian Sleipner and Snovhit projects. The global quest for oil has resulted in exploration and production of green fields such as the U.S. shale formations, Canadian heavy oil sands, and the innovative hydraulic fracturing and horizontal drilling technology. However, EOR in depleted and mature oil fields potentially recovers 10-40% OOIP. Current offshore gas EOR includes the recent Mexican Cantarell field in offshore Gulf of Mexico immiscible nitrogen injection project (Sanchez et al., 2005), and Brazil's Lula field pilot CO_2 EOR project. Offshore geological storage in the Sleipner project alone successfully sequestered approximately 10 million tons of CO_2 in the North Sea sub-seabed in 10 years (MITei, 2014). In this study, I have shown that after screening out gas sands, 3,598 of the studied offshore GoM oil reservoirs (sands) could potentially store 2.2 billion metric tons of CO_2 before EOR; the storage capacity after EOR increased to 2.5billion metric tons. Onshore GS studies such as Benson et al. (2005): "*Lessons learned from natural and industrial analogues for storage of carbon dioxide in deep geological formations*" could provide guidance relevant to offshore sub-sea formations. Other assessments applicable to CO_2 sequestration in oil fields can be adapted from publications such as Gill (1982), Vignes et al. (2010), and Hosseini et al. (2013).

Although CO_2 flooding is known to EOR by at least 10 percent of OOIP, operators are burdened with the cost of retrofitting new CO_2 EOR design into existing offshore platforms. To prevent expensive and complex offshore CO_2 EOR retrofit or installation, newly discovered deep and ultra-deep oil fields that are candidates for future CO_2 EOR could be built incorporating CO_2 flooding in its front end engineering design (FEED).

According to Malone et al. (2014), the Lula field offshore Brazil pilot proactively initiated CO_2 EOR in its platform design during its primary oil production phase. Experience from the 1980s US offshore pilot projects, Lula oil field and Sleipner's offshore sequestration could provide a basis for future offshore GoM CO_2 EOR/GS projects. More useful information is provided in Godec et al. (2013) publication on *"Anthropogenic CO_2 EOR/sequestration"*, and Choi et al. (2013) *"Assessment of CO_2 recycling accounting for EOR."* According to Malone et al. (2014), implementing CO_2 EOR in the depleted shallow water GoM fields that are near abandonment, removes the incremental cost associated with decommissioned platforms.

Another challenge both oil operators and large volume CO_2 emitters face with CO_2 EOR is the distance from CO_2 source to oil platform or GS formation. In addition to cost of CO_2 capture and processing, CO_2 transportation cost significantly affects CO_2 EOR economics based on pipeline design and construction. The issue of CO_2 transport is lessened when the CO_2 source-feed is within the offshore oil producing field or lies in close proximity to the oil field. Again, this is the case for the Brazilian Lula oil field which has its CO_2 source from its produced gas. A probable motive for the Lula oil field CO_2 EOR pilot project could be its hydrocarbon gas comprising about 8 – 15% CO_2 (DiPietro et al. 2014). Offshore GoM new oil fields could take a similar approach especially if there are fields with similar hydrocarbon gas composition as the Lula oil field. Further study to determine offshore CO_2 sources may reveal potential source-feeds in offshore GoM gas reservoirs, especially because there are more non-associated gas fields than there are oil fields in the OCS. Likewise, offshore GoM oil fields that have high gas oil ratios may be considered for future study of offshore CO_2 sources.

During CO_2 flooding, gas exchange occurs between the injected gas and native hydrocarbon gas. As discussed earlier, in-situ mass transfer of native hydrocarbons would

overtime increase the volume of native CH_4 in the recycled CO_2 EOR solvent. Removing CH_4 or other native hydrocarbon gasses after each CO_2 flood cycle would significantly increase OPEX of the EOR project, making this less attractive for operators. Alternatively, the CO_2 solvent is repeatedly injected or recycled regardless of the increasing impurity mole fraction of native hydrocarbon gases. This study showed that while some offshore GoM fields remained miscible at up to 40 mole percent CH_4 impurity in the CO_2 solvent, others converted to immiscible fields at CH_4 impurity levels less than 10 mole percent. To achieve miscibility in at least 70% of these reservoirs, 18 mole percent was established as the cutoff for CH_4 impurity in injected CO_2. At 10 mole percent CH_4, about 89% of the case study fields were miscible. A decline in number of miscible reservoirs occurred as CH_4 impurity levels increased in the recycled CO_2 solvent. When the impurity increased to 20 mole percent CH_4, only 64% of the reservoirs were amenable to miscible CO_2 EOR. Therefore, at CH_4 impurity levels above 18 mole percent, some options offshore GoM CO_2 EOR are;

(i) CO_2 solvent processing and separation of impurities,

(ii) Repurchase pure CO_2,

(iii) Switch to immiscible gas EOR

The economics of these three options were not assessed in this study, however a comparative assessment would establish or eliminate each option.

It takes more than sophisticated technology and economics for geological sequestration and commercial CO_2 EOR to be implemented. Other factors such as safety, fiscal terms, concessions, oil and gas law, and environmental law cannot be neglected. One objective of environmental law is to protect the environment for present and future generations. Inadequate legal framework is one barrier to the advancement of offshore CCS. Although, the U.S. has existing regulations established for CO_2 EOR, anthropogenic

CO_2 injection for the purpose of GS or EOR has only recently been recognized. Enacting legislation by setting a limit on CO_2 emission could foster an alliance between large volume anthropogenic CO_2 emitters and oil producers, who need CO_2 as miscible injection fluid for EOR. Presently, some US oil and gas companies as well as electric utility companies have taken proactive steps towards GHG mitigation in anticipation of a new climate change legislation that would provide economic incentives for carbon reduction. CO_2 EOR provides commercial benefits to geologic sequestration by increasing oil production in mature reservoirs. However, not all mature oil fields can adapt CO_2 EOR based on the physical and geologic properties of the reservoirs. This is another motivation of GS without EOR because of its potential to store CO_2 that would otherwise be vented to the atmosphere. A comprehensive legal framework addressing the barriers stated in this thesis could provide a shift towards timely CCS implementation.

Offshore GoM is advantageous because the US OCS is not burdened with pore space rights that arise in US private properties. In the US alone, surface rights may be separately owned from mineral rights. Also only in the US are there interstate variations to surface rights and mineral rights. These factors make geologic storage in offshore fields less cumbersome compared to onshore fields. Other reasons offshore sequestration is preferred to onshore underground storage are:

- its location is away from drinking water aquifers and human population,
- the availability of massive sub-seabed storage sites with the ability to contain larger volumes of CO_2 and,
- the potential to EOR in CO_2 amenable oil reservoirs.

Fossil fuels remain a major source of global energy and will continue until advances in renewable energy technology become a substitute. Until such a time, carbon sequestration technology can be implemented towards GHG mitigation and EOR.

Glossary

Anthropogenic	Product of human activities on nature; example CO_2 gas emissions
Anticline	An arch shaped geologic structure or fold that forms a potential trap for hydrocarbons in oil bearing formations
Bathymetric	A survey on seabed topography
Capillary force	"*Interfacial force between immiscible fluid phases that creates pressure difference between the two phases*" (NIPER, 1986)
Capture	Technology that gathers anthropogenic CO_2 from a large volume emitting sources before or after combustion
Climate change	Climatic variations and inconsistency in weather patterns
CO_2 EOR	A gas EOR technology that injects supercritical CO_2 as displacement fluid. Also referred to as CO_2 flooding
Critical temperature	The temperature at which substance can only exist in its gaseous state irrespective of pressure
Cumulative gas production	Total periodical gas production from a reservoir or field to date, commonly computed based on annual production rates.
Cumulative oil production	Total periodical oil production from a reservoir or field to date, computed based on annual production rates.
Displacement efficiency	*"Ratio of the amount of oil recovered from a zone swept by a displacement fluid such as in a CO_2 flood to the amount of oil present in the swept zone prior to commencing the CO_2 flood"* (NIPER, 1986)
Enhanced oil recovery	*abbrv. (EOR)* A tertiary oil recovery mechanism that occurs after waterflood. It involves flooding with

	elements that contact the reservoir to improve oil production. Types of EOR include gas, polymer, thermal, chemical and microbial process EOR.
FEED	*abbrv.* Front End Engineering Design. Basic engineering after completing conceptual selection or feasibility study in a project
Gas cap	Gas phase overlying an oil zone and occurring in saturated oil reservoirs. Also called free gas
Geologic storage	Large volume CO_2 storage in underground geological formations
Greenhouse gas	*abbrv. (GHG)* Consist mainly of CO_2. GHG increase atmospheric heat and is the major cause of global warming
Immiscible	Two fluids that do not mix homogenously, thereby forming an interface
Impurity	Gas component that alters the properties of the original solvent
Incremental oil	Difference between oil productions from EOR to oil production from conventional primary or secondary recovery
Minimum miscibility pressure	*abbrv. (MMP)* The minimum pressure at which reservoir oil is miscible with the injected solvent (such as CO_2), at reservoir temperature
Miocene	The first geological time that extends from about 23.0 million years ago to 5.3 million years ago
Miscibility	A condition where two fluids homogenously mix in all proportions without forming an interface between them
Mitigate	Techniques or processes that reduce the impact or interference of anthropogenic emissions on the climate
Mobility ratio	The ratio between the mobility ratio of the injection solvent (CO_2) to the mobility ratio of the reservoir oil

Molecular weight	Average mass of a molecule calculated by summing the atomic weights of comprising atoms
Oil formation volume factor	*abbrv.* (B_{oi}) Ratio of volume of oil at reservoir conditions to volume of oil at surface conditions measured as barrel/stock tank barrel
Original gas in place	*abbrv. (OGIP)* Estimated reservoir gas volume prior to production
Original oil in place	*abbrv. (OOIP)* Estimated reservoir oil volume prior to production.
Play	Group of accumulations in a hydrocarbon bearing formation that have closely related geological features. Play types include: fan play, fold belt, aggradational, retrogradational and progradational.
Pleistocene	The earliest Epoch of the quaternary period in geologic time that extends from about 1.6 million years to 10,000 years ago. Commonly known as the Ice Age
Pliocene	The latest Epoch of the tertiary period in geological time that began about 5.3 million years ago to 1.6 million years ago
Post-combustion	CO_2 capture from large volume anthropogenic source after combustion is completed
Pre-combustion	Removing CO_2 large volume anthropogenic source before combustion is completed
Primary oil recovery	Oil recovery through reservoir natural drive
Pseudocritical temperature	The temperature at which two or more gases mix as a function of their concentration and joint critical temperatures
Pure CO_2	100% carbon dioxide composition
Reservoir type	Reservoir classification based on the dominant reservoir type. Oil sands with multiple reservoirs are defined by

	the reservoir type with the highest count. See saturated, undersaturated and nonassociated gas reservoirs
Residual oil	Reservoir oil in formation after conventional oil recovery (primary and secondary recovery)
Sands	Conventional oil and gas reservoirs in the US outer continental shelf. They do not represent heavy oils with low API gravity such as the Canadian oil sands or bitumen. These sands are categorized as oil sand, gas sands or combination sands (i.e. oil and gas) based on their dominant production
Saturated reservoir	Defines reservoirs with pressure below bubble point pressure. These reservoirs have a gas cap
Screening	Critical elements considered during assessment of EOR viable reservoirs
Secondary oil recovery	Oil recovery through water injection or water flood
Sequestration	A process that involves capture of anthropogenic CO_2 for long term to permanent storage in underground geological formations
Sub-seabed depth	True vertical depth sub-seabed (BOEM, 2014)
Sub-seabed	Beneath the seafloor or seabed
Supercritical fluid	Physical state above critical temperature where a substance exhibits both gas and liquid properties
Sweep efficiency	*"Ratio of pore volume of reservoir rock contacted by injected fluids to the total pore volume of reservoir rock in the project area"* (NIPER, 1986)
Undersaturated reservoir	Defines reservoirs with pressure above the bubble point pressure. These reservoirs don't have a gas cap, but do have dissolved gas (associated gas)

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